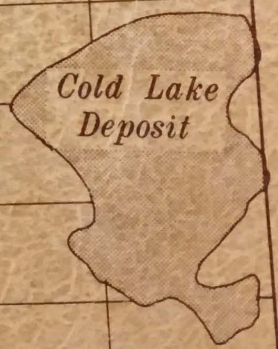
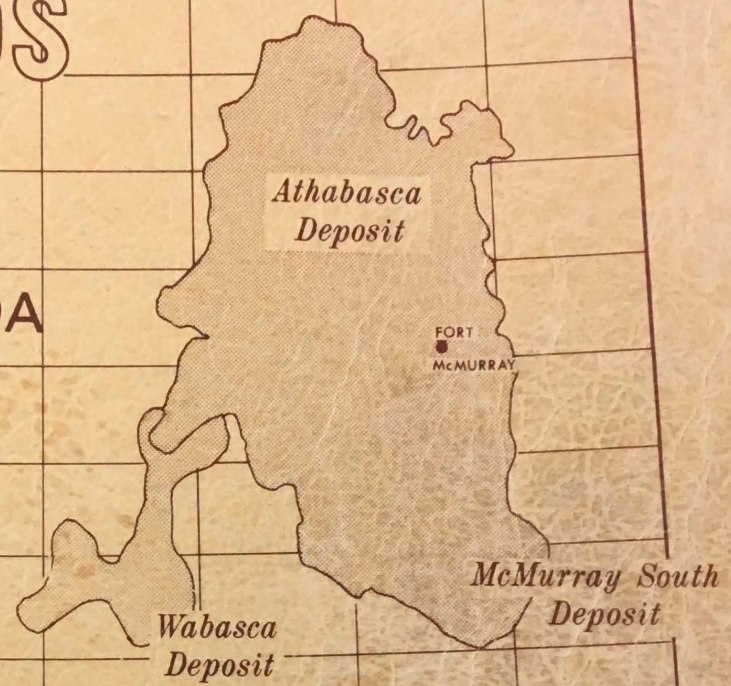
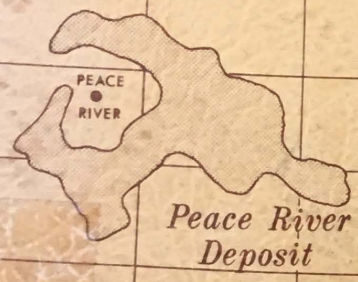


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B.H. Sherwood

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the  
**TAR SANDS**  
of  
**ALBERTA, CANADA**



by  
Dr. F. W. Camp

SECOND EDITION





*W. T. Camp*

THE  
TAR SANDS  
OF  
ALBERTA, CANADA

DR. FREDERICK W. CAMP  
SUN OIL COMPANY

SECOND EDITION

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"ENCYCLOPEDIA OF CHEMICAL TECHNOLOGY," VOLUME 19,  
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## FOREWORD

The first edition of "The Tar Sands of Alberta, Canada" was published in 1970 and was so popular that the first printing was quickly exhausted. The decision to publish a second edition rather than merely reprint the first, was made in early 1973, but was delayed for several reasons, including a strike at Sun Oil Company's Marcus Hook refinery which drew Dr. Camp's attention for several months. Aside from disturbing set schedules delays also frequently serve to outdate material before it is published. In this instance, however, the delay provided the opportunity to include new information on commercial ventures recently proposed by Shell Canada, Ltd. and Petrofina Canada, Ltd. and to provide more up-to-date coverage of the continually unfolding story surrounding the commercial venture proposed by Syncrude Canada, Ltd. The second edition also contains additional information pertaining to bitumen conversion, upgrading and refining.

Dr. Frederick W. Camp is uniquely qualified to address the subject of tar sands. As a member of the Applied Research Department of Sun Oil Company, he became involved with the Great Canadian Oil Sands project in 1964 where, during pilot plant operations, he was concerned with data analysis and the establishment of the plant design basis. Continuing with the GCOS project through 1968, he contributed directly to defining the hot water extraction mechanism and the principal design criteria; he acted as a consultant during startup. Dr. Camp's interest in tar sands goes beyond the plant gate at GCOS as evidenced by his colorful account of the history of the Alberta tar sands.



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## INTRODUCTION

Tar sands (also known as oil sands and bituminous sands) are sand deposits which are impregnated with dense, viscous petroleum. Tar sands are found throughout the world, often in the same geographical area as conventional petroleum. The largest deposit, and the only one of present commercial importance, is in the Athabasca area in the north east of the Province of Alberta, Canada. This deposit contains over 700 billion barrels of bitumen. For comparison, this is about 1/6 of the U.S. shale oil reserves, and about 1/16 of the U.S. coal reserves.

Tar sands have the interesting property that the bitumen is often rather easy to separate from the sand by a wide variety of methods. Tar sands have provided, at least in the U.S. and Canada, grist for the mills of innumerable kitchen-sink inventors. An extensive patent literature [1,66]\* testifies to this fact. Despite the fact that tar sand deposits have been known for many years, and the bitumen separates rather easily from the sand, it is only recently that tar sands have assumed commercial importance. The first venture for manufacturing synthetic crude oil from the sands, by Great Canadian Oil Sands, Ltd., is now in operation.

The Athabasca tar sand deposit was first recorded in 1788. Serious mapping and exploration awaited the work of S. C. Ells, of the Federal Canadian Department of Mines and Technical Surveys, starting in 1913. From that time until about 1945, except for the continuing research program of the Research Council of Alberta, little interest was expressed in the Athabasca deposit. During the Second World War, with the real possibility of an oil shortage in Canada and the U.S., an extensive program of exploration was undertaken by the Canadian Government. Between 1940 and 1950, pilot plants were sponsored by both the Federal Canadian Government and the Government of the Province of Alberta. During 1948-49 the hot water separation process was demonstrated on pilot plant scale under the technical supervision of Dr. K. A. Clark. In 1950 the Blair Report [5] was published. This engineering study concluded that production of synthetic crude oil from the Athabasca tar sands was technically and economically feasible. From 1955 on, industrially sponsored research has been steadily increasing, leading to five formal proposals for commercial ventures.

\*Numbers in brackets refer to bibliography beginning on page 73.



Among the methods for recovering bitumen from tar sands are fire floods, a steam drive process, and atomic explosion (all in situ recovery processes). Processes operating on tar sand which has been mined include direct coking of the tar sand, and hot water, cold water, and solvent processes for extracting bitumen from the sand. Bitumen itself is too dense (6-10°API) and viscous (5,000 - 50,000 poise @ 50°F) to be either saleable or transportable. Many upgrading processes have been proposed, including partial coking, conventional delayed coking with catalytic hydrodesulfurization of the coker distillate, and direct catalytic hydrovisbreaking of bitumen. Commercial ventures for bitumen recovery from the Athabasca tar sands have been proposed by Shell Canada, Limited (steam drive in situ recovery process followed by thermal cracking and hydrotreating); Shell Canada, Limited (mining project); Muskeg Oil Company (combination of forward combustion and water flood); and Syncrude Canada Limited, (mining, hot water extraction of bitumen, coking and hydrotreating). Great Canadian Oil Sands, Ltd. (mining, hot water extraction, coking and hydrotreating) is in commercial operation.



## OCCURRENCE AND RESERVES

### RESERVES

Various definitions have been applied to energy reserves [6]. What are usually called proved reserves have a rather limited and specific meaning. These are reserves recoverable under current conditions of technical and economic feasibility. Proved reserves give an accurate, short-term estimate of the working inventory of a particular resource. The proved U.S. reserves of crude oil, for instance, remained relatively constant during the period 1954-1969 despite the fact that 8-10% of this figure was consumed each year [68]. Starting in the late 1960's however, the reserve/production ratio started a precipitous drop, which was only temporarily reversed in 1970 by addition of the Alaskan North Slope reserve. In a sense, proved reserves represent the economic balance between the present cost or risk of committing capital to exploring for more crude, and the future risk of a deficiency in a crude supply. The drop in reserve/production ratio parallels a period of rapidly increasing finding costs for new oil.

Ultimate reserves, or in-place reserves, are defined much more broadly as the largest reasonable estimate of the total amount of a particular resource. Not only discovered, but also "discoverable" (based on reasonable geological extrapolations) resources are included. The estimate is not limited to today's economic conditions or recovery technology. Because of the differences in definition, it is not meaningful to compare reserves using different calculation bases.

Table 1 compares proved and ultimate reserves for a number of energy sources. While tar sands are not a major energy reserve, they certainly are significant in comparison to projected energy consumption over the next several generations. Recently in the popular press, tar sand reserves (ultimate) have been compared to proved crude oil reserves. Such a comparison creates the misleading impression that tar sands are a fantastically large resource.



## ATHABASCA TAR SANDS

### Location and Geology

The Athabasca tar sands are located in the northeast of the Province of Alberta, Canada. Figure 1 locates world tar sand reserves; Figure 2 gives the geographical location of Alberta's tar sand deposits and major conventional oil fields; Figure 3 shows the northern tar sand deposits in Alberta; Figure 4 is a geological cross section of the northern deposits. The Athabasca tar sands deposit is the largest and the only one currently under commercial exploitation. Experimental projects have also been carried out in the Peace River and the Cold Lake deposits.

TABLE 1

Energy Reserves<sup>1/</sup>  
Expressed in Q's<sup>1/</sup>

Resource	Proved <sup>2/</sup>		Ultimate <sup>2/</sup>		Predicted U.S. Consumption 1960-2000
	USA	World	USA	World	
Crude Oil	0.2	2.3	6.0	37.0	1.3
Natural gas & NG Liquids	0.3	0.9	3.2	19.6	1.1
Shale Oil	0.3	0.9	23.2	79.0	-
Coal	4.6	18.0	55.0	320.0	0.5
Uranium <sup>3/</sup>	0.2	0.7	1.2x10 <sup>5</sup>	-	-
Deuterium <sup>4/</sup>	-	-	-	7.5x10 <sup>9</sup>	-
Tar Sands	-	-	0.01	6.5	-

<sup>1/</sup> Q = 10<sup>18</sup> BTU = 167 x 10<sup>9</sup> BBL (crude oil)

<sup>2/</sup> Including U.S.

<sup>3/</sup> Proved reserves assume 1% recovery of maximum theoretical fission energy content and mining costs of \$5 to \$10 per lb. of U<sub>3</sub>O<sub>8</sub>. Ultimate reserves assume 100% theoretical energy content and no mining cost limit.

<sup>4/</sup> By nuclear fusion.

Source, [7,8,9]



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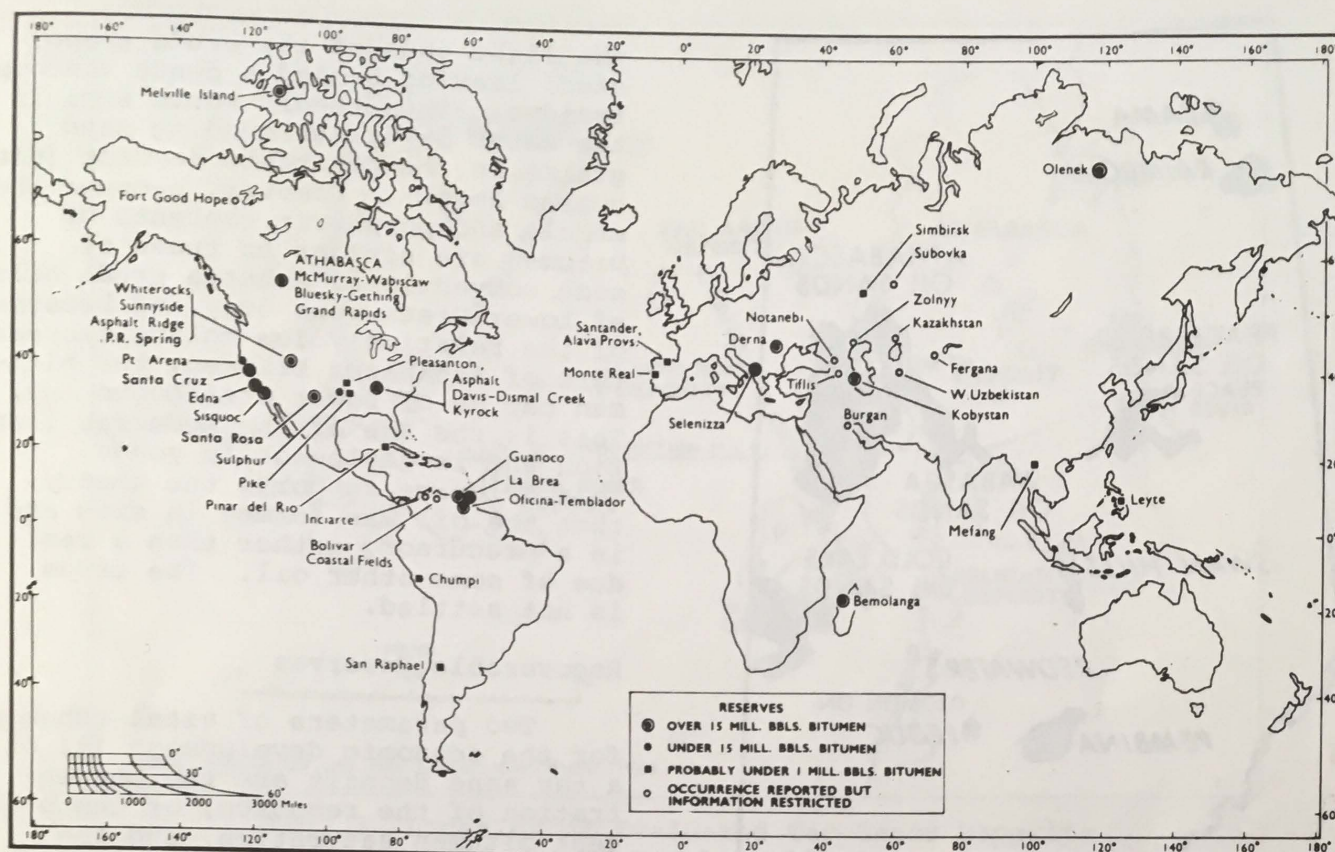


Fig. 1 Tar Sands of the World, Source [9]

The main geological features of the Athabasca deposit can be seen in Figure 4. The floor of the deposit is limestone of Devonian age. Above the Devonian base occur, in order, the McMurray, Clearwater, and Grand Rapids formations. The McMurray formation is a layer of sand, cross-bedded in some locations with lenses of clay and shale. Where the McMurray formation has been impregnated with bitumen it is the tar sands. Along the Athabasca River, north of the town of Fort McMurray, for several miles east, and more particularly to the west, the Clearwater and Grand Rapids formations may be absent. These formations are sandstone and shale layers without bitumen saturation. Where they have weathered away, outcrops of tar sands can be observed along the Athabasca River bank for about a hundred miles to the north of Fort McMurray.

There are two schools of thought regarding the origin of the oil. One [47] is that the oil was formed locally, and has neither migrated a great distance, nor been subjected to large overburden pressures. Since under these conditions, the oil cannot have been subjected to thermal cracking, it is geologically young and therefore dense and viscous. The opposing theory [48] assumes a remote origin for the oil, both geographically and in geological time. The oil, originally like a conventional crude, is assumed to have migrated into the sand deposit which may originally have been filled with water. After the oil migrated the overburden pressures were relieved, and



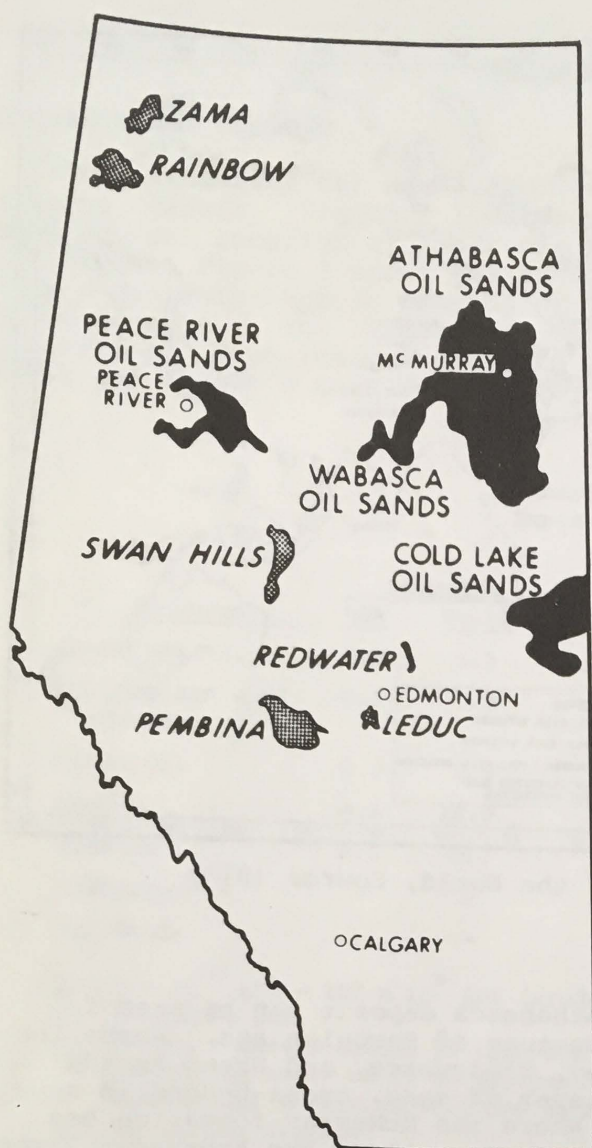


Fig. 2 Major Oil Sands Deposits of Alberta, Source [67]

the order of 1.0. The Athabasca tar sands have a maximum thickness of about 300 feet, and average about 150 feet. Referring to Figure 6, this implies that no more than 10% of the in-place deposit is mineable within current concepts of the economics and technology of open pit mining. The Energy Resources Conservation Board of the Province of Alberta considers 120 feet overburden thickness the practical limit for mining [67]. At the other end of the overburden scale are the in situ processes. Each of these depends on injecting a driver substance into the ground through injection wells, and recovering bitumen through production wells. All such processes need a relatively thick layer of overburden to contain the driver substance within the formation between injection and production wells. If, in this context, a thick overburden layer can be taken to mean upwards of 250 feet, then much of the

the light ends of the crude evaporated, leaving behind a dense viscous residue. This theory would explain the water layer surrounding sand grains in the Athabasca deposit (discussed below). However, because the metals and porphyrin contents of bitumen are similar to those of some conventional Alberta crude oils of Lower Cretaceous age, and because of the relatively low coking temperature of Athabasca bitumen, the bitumen may be of Lower Cretaceous age. This is the age of the McMurray formation and is geologically young. This evidence supports the theory that the oil was formed in situ and is a precursor, rather than a residue of some other oil. The issue is not settled.

#### Recoverable Reserves

Two parameters of vital concern for the economic development [7] of a tar sand deposit are the concentration of the resource, or the percent bitumen saturation, and the accessibility, usually measured by the overburden thickness. Figures 5 and 6 summarize the overburden thickness and bitumen saturation for the Athabasca deposit. Recovery methods may be generally divided into those which depend on mining, combined with some further processing, and those which attempt to operate on the oil sands in situ. The mining methods are applicable to shallow deposits, characterized by an overburden ratio (overburden depth/depth of tar sand deposit) on



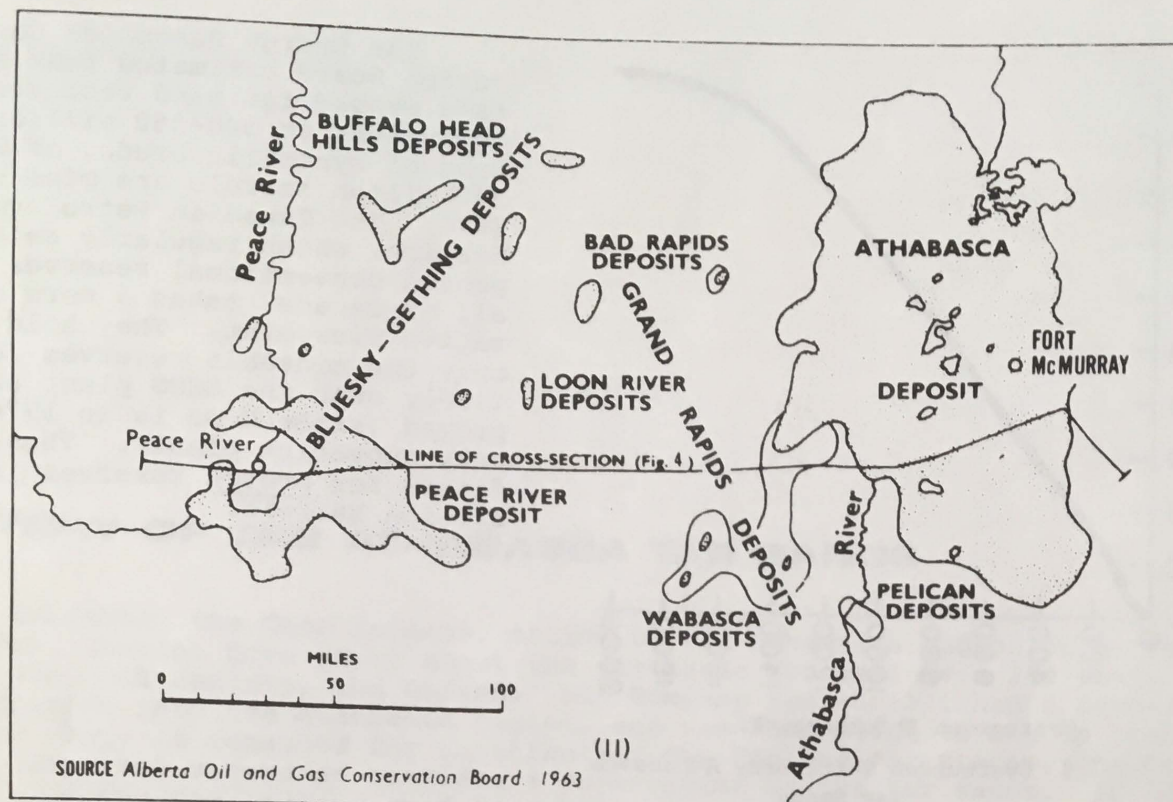


Fig. 3 Location of Evaluated Tar Sands Deposits of Northern Alberta

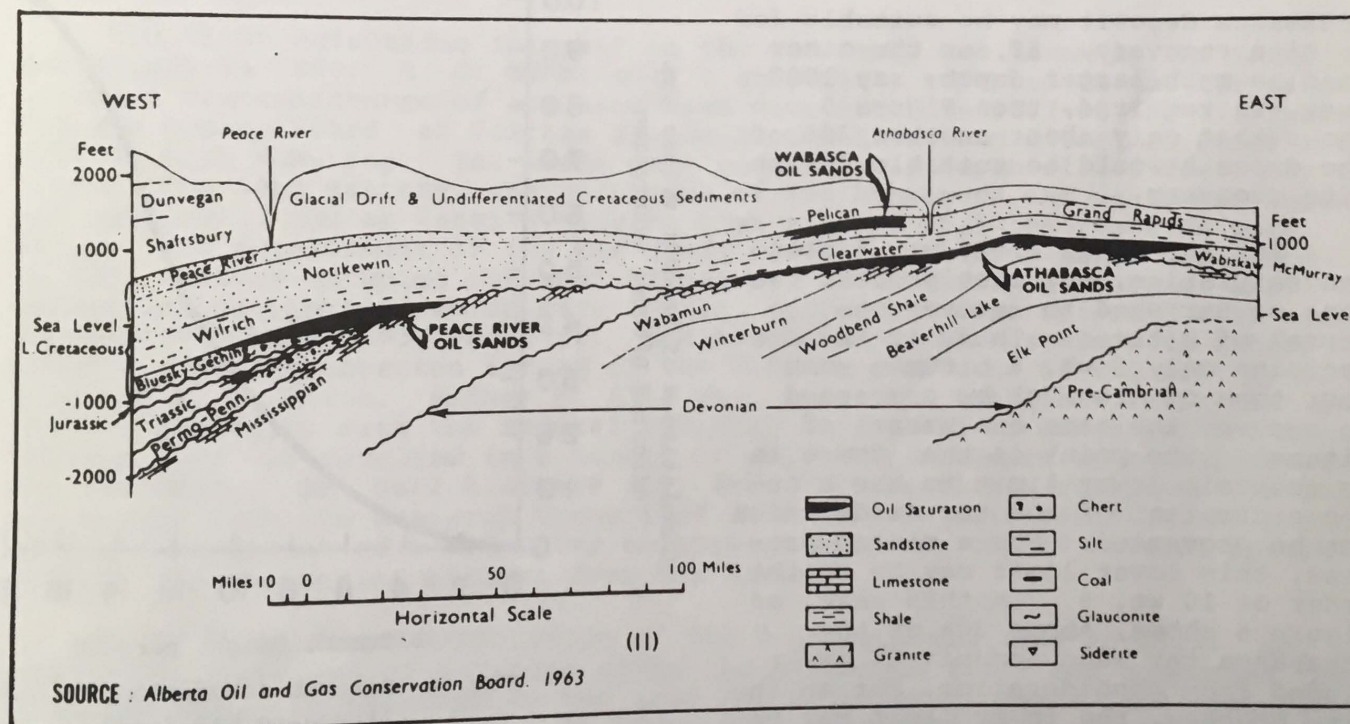


Fig. 4 Schematic Geological E-W Cross Section, Athabasca Tar Sands



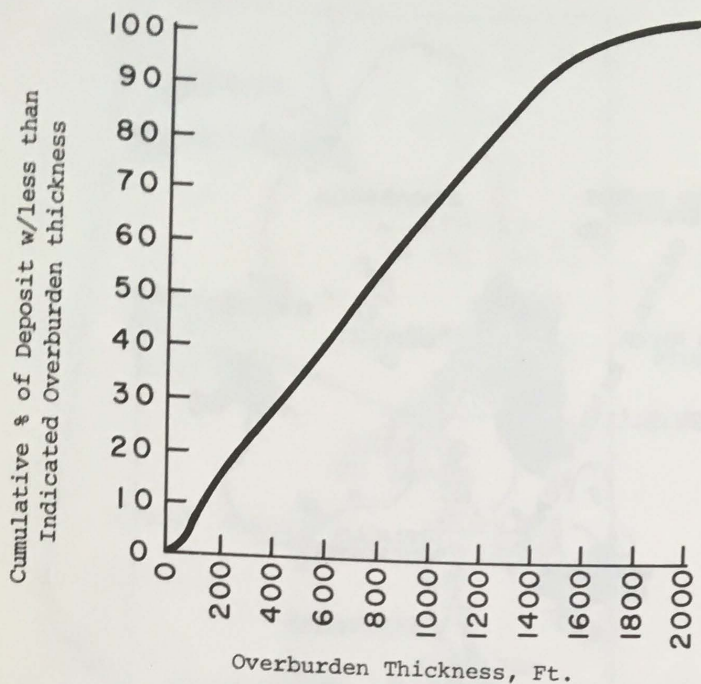


Fig. 5 Overburden Thickness, Athabasca Tar Sands  
Source: [11]

Athabasca deposit may be suitable for in situ recovery. If, on the other hand, a much larger depth, say 1000 feet, is required, then Figure 5 shows that only about another 30% of the deposit would be suitable for in situ recovery.

For tar sands of 10 wt. % bitumen saturation, one must process two tons of tar sand to recover one barrel of bitumen. Thus, if the ore contains only 5 wt. % bitumen some four tons of ore must be processed to recover the same one barrel of bitumen. The point is that there is an economic lower limit to the bitumen saturation of the tar sands which can be processed. For a mining process, this lower limit may be on the order of 10 wt. %. In this case, as Figure 6 shows, about 30% of the Athabasca tar sand deposit is excluded from consideration. For an in situ process, the lower limit may be somewhat less.

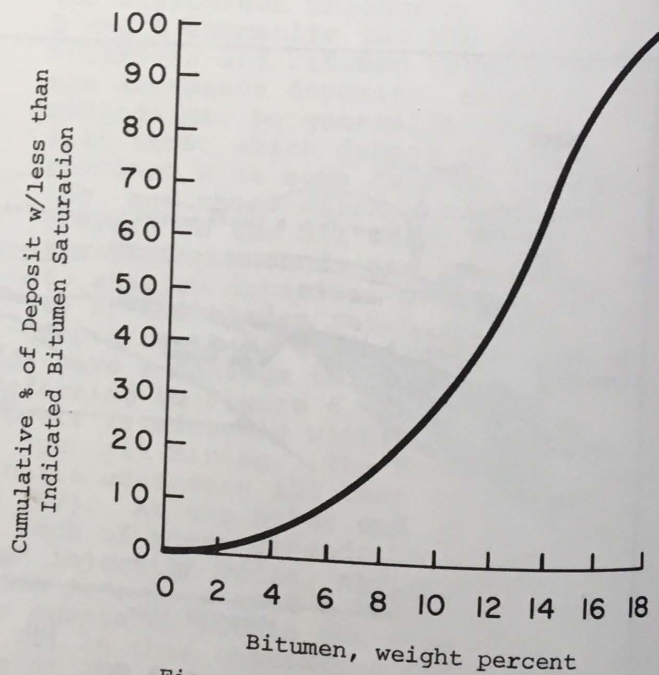


Fig. 6 Bitumen Saturation, Athabasca Tar Sands  
Source: [11]

The Energy Resources Conservation Board estimates that Alberta's proved tar sand reserves are equivalent to 340-350 billion barrels of synthetic crude, of which 34 billion barrels are mineable [67]. The Canadian Petroleum Association, which regularly calculates proved conventional reserves for all of Canada, takes a more conservative viewpoint. They hold that only the mineable reserves relatively near the GCOS plant are proved (since GCOS is in 1974 the only operating plant). Thus, CPA's figure for proved reserves is 6.2 billion barrels.



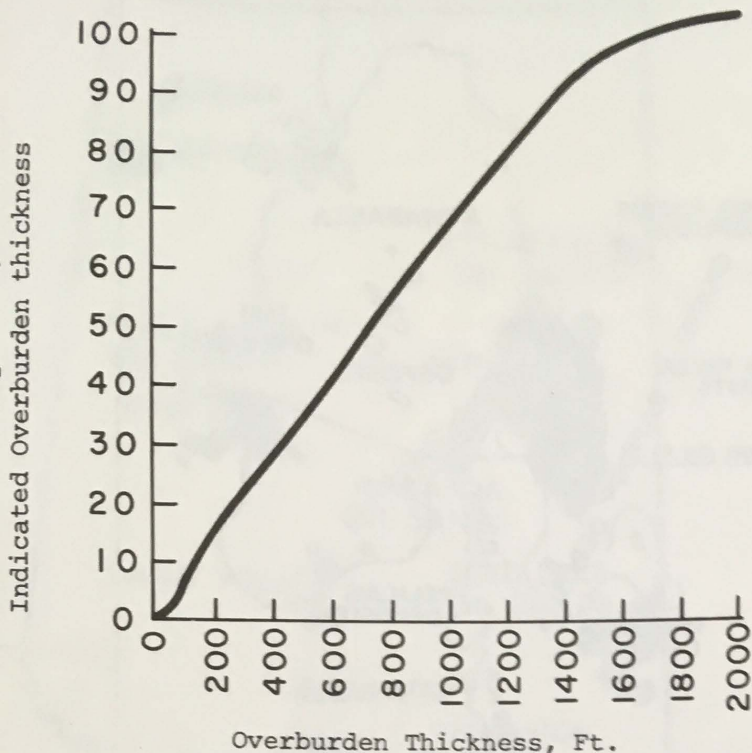


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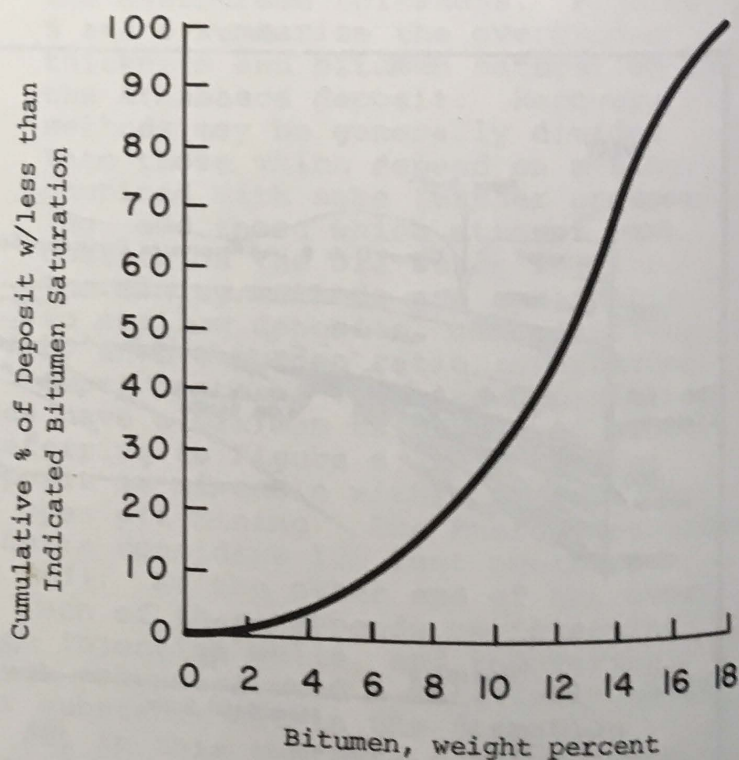


Fig. 6 Bitumen Saturation, Athabasca Tar Sands  
Source, [11]



## HISTORY OF THE ATHABASCA TAR SANDS

Evidently the Cree Indians, native to the Athabasca region of northeastern Alberta, Canada, have known about the tar sands for well over 200 years. By the late 18th century, the Hudsons' Bay Company had established a commercial penetration into the Athabasca region, and was attempting to set up trading posts. Yet, it remained for an itinerant New England fur trader, one Peter Pond, to first record an outsider's observation of the tar sands. In 1788, Pond told how the Indians used "a sticky substance oozing from the river banks to waterproof their canoes." Peter Pond established a successful trading post near the site of the present town of Fort McMurray (see Figure 1) where the Clearwater and Athabasca Rivers join. In 1870, the post received its present name, Fort McMurray.

The first scientific interest in the tar sands was taken by the Canadian government in 1890. R. G. McConnell, a geologist, reported on the tar sands during a reconnaissance of the Athabasca district. In 1897-98 the first drilling was accomplished at Pelican Rapids on the Athabasca River, 80 miles southwest of Fort McMurray. Tar sands were reached at a depth of 740 feet. By the turn of the 20th century, the existence of the Athabasca tar sands was known and confirmed, and at least a general idea existed that the reserves were large. The development of the tar sands to the point of a large scale commercial venture occupied the next 67 years. It is mainly a story of small commercial enterprises which were formed, failed and were reformed with some regularity between 1930 and 1960. Behind the story of unsuccessful entrepreneurs runs the unbroken thread of the life-long efforts of two men, S. C. Ells and K. A. Clark. Sidney C. Ells was, from 1913 until his retirement in 1945, a geologist with the Federal Canadian Department of Mines and Technical Surveys. He was involved in a number of the early attempts to commercialize the tar sands. Dr. Karl A. Clark was, from 1920 until his retirement in 1954, associated with the Research Council of Alberta. In this position, he pioneered the development of a hot water separation process, one of several possible methods for recovering bitumen from tar sands.

S. C. Ells' first exploration of the Athabasca was made in 1913. He sampled the outcrops of tar sand along the Athabasca River and commenced the first surveys. He returned to the area for a number of years and produced the first comprehensive maps. In 1922, Ells succeeded in interesting a group



of New York City policemen in forming the Alcan Oil Company. This company failed forthwith, and in 1923 the assets were taken over by R. C. Fitzsimmons, who formed International Bitumen Company. International Bitumen first exploited the tar sands commercially. In 1930, a works was operated at Bitumount about 60 miles north of Fort McMurray on the east bank of the Athabasca. Several thousand barrels of tar were recovered and sold in Edmonton as a roofing material. Also in 1930, Dr. Clark established a small pilot plant on the Clearwater River, under the auspices of the Research Council of Alberta. It was the first onsite experimental unit devoted to developing an efficient separation process; it had earlier been operated in Edmonton.

In 1930, still another chain of development efforts was started. In consultation with S. C. Ells, Mr. Max W. Ball formed Canadian Northern Oil Sands Products, Ltd., later reformed as Abasand Oils Limited. In 1936 Abasand started construction of a 250 ton per day separation plant on the Horse River, just south of Fort McMurray. From 1937 to 1941, construction was undertaken on a second plant, rated at 400 tons per day. During the summer of 1941, some 17,000 barrels of bitumen were produced, and refined to distillate petroleum products. In November of the same year, the plant burned down. In 1942 the separation plant was rebuilt, but in 1943 Ball's financing failed. The Dominion Government took over the Horse River separation plant. During 1944 the plant was redesigned and revised, with a rated capacity of 100 tons per day. This was to be the pilot unit for a larger 500 ton per day plant which was completed in 1945. These plants never operated; they burned to the ground on June 15, 1945.

The International Bitumen Company operations were not continued after 1930. In 1942, L. R. Champion acquired the assets of International Bitumen and formed Oil Sands, Ltd. By 1944, Champion had arranged with the Alberta Research Council to help in financing a test plant, but in 1948, Champion's financing failed and the Alberta Government assumed control of the newly-built test plant at Bitumount. The plant was operated during 1948 and 1949 under the supervision of Mr. W. E. Atkins. Technical support was provided by the Research Council under Dr. Clark's direction. These operations were reported in detail [12, 52]. An independent engineering analysis based on this work, the Blair Report [5], was a detailed study of the technical and economic feasibility of a tar sands separation venture. The Blair Report was optimistic, and spurred the interest of several investigators during the next decade. In 1953, the Oil Sands Ltd. interests were reformed as Great Canadian Oil Sands, Ltd. (GCOS). At the same time the Government moved to divest itself of the Bitumount holdings. In 1955, these were sold to Can-Amera Oil Sands Development Company. During 1955 to 1959, the facility was again operated by Can-Amera and Royalite Oil Company.

Since 1957, four extensive pilot plant operations have been conducted in the Athabasca, each leading to a proposal for a commercial venture. During 1957-1962, Shell Canada Ltd. tested in situ recovery of bitumen from the tar sands. Pan American Oil Corp. started laboratory work on in situ recovery in 1956; field operations were conducted from 1958 until 1968. During 1959-1962 a group headed by Cities Service Athabasca Ltd., and including Imperial Oil Ltd., Richfield Oil Corp., and Royalite Oil Company Ltd. operated a pilot plant at Mildred Lake, based on a hot water extraction process. During 1963-1965, Great Canadian Oil Sands, Ltd. operated a pilot plant at the present commercial plant site near Mildred Lake. Other field operations in the Athabasca region include Mobil (1965), Canadian Fina (1967-70) and Texaco (1972-present). In 1971, Amoco reactivated the Pan American project.



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The ruins of several of the early tar sand ventures may yet be seen. The burned-out remains of the Abasand plant are easily located on the Horse River south of Fort McMurray, near what is now a community fishing ground. Likewise, just across the Clearwater River from Fort McMurray, the remains of the first Clark test plant are visible. At Bitumount, both the International Bitumen Company plant and the Oil Sands, Ltd. test plant are still standing. Only the Oil Sands, Ltd. plant was not destroyed by fire.

## PROPERTIES AND CHARACTERISTICS ATHABASCA TAR SANDS

The Athabasca tar sands have been described as a mixture of sand, water, and bitumen. The sand is composed of rounded grains of quartz, and the bitumen is a heavy, viscous liquid. The mixture is known as a "tar sand" because of the high percentage of bitumen it contains. The bitumen is a complex mixture of hydrocarbons, and its properties are determined by the composition of the sand and the amount of bitumen it contains. The Athabasca tar sands are found in a large area of the province of Alberta, Canada, and are one of the most important sources of bitumen in the world.

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## PROPERTIES AND CHARACTERISTICS ATHABASCA TAR SANDS

### BULK PROPERTIES

Tar sand has been defined [11] as sand saturated with a "highly viscous crude hydrocarbon material not recoverable in its natural state through a well by ordinary production methods." Strictly speaking, the material should perhaps be called bituminous sand rather than tar sand since the hydrocarbon is a bitumen (carbon disulfide soluble oil). In petroleum refining, tar is a term reserved for the residue of a thermal process. The term oil sand is used also, possibly in allusion to the synthetic crude oil which can be manufactured from the bitumen.

It has long been realized that tar sand is a mixture of sand, water, and bitumen, arranged as shown in Figure 7. The sand component is predominantly quartz, in the form of rounded or subangular particles. Each is wet with a film of water. Surrounding the wetted sand grains, and somewhat filling the void volume among them is a film of bitumen. The balance of the void volume is filled with connate water, plus, in some instances, a small volume of gas. The gas is usually air, but some test borings in the Athabasca deposit have reported methane. The sand grains are packed to a void volume of about 35%. This corresponds to a tar sand mixture of roughly 83 wt.% sand, the balance being bitumen and water. In fact, it is found with considerable regularity, that the bitumen and water weight percentages total about 17% of the tar sands.

Two figures of merit are applied to tar sands with respect to hot water processing. These are percent bitumen and percent fines. Percent bitumen may be determined analytically by solvent extraction. Toluene saturated with NaOH is a suitable solvent, and the extraction may be so arranged that both the water and bitumen contents are measured directly. Percent fines, as used below, refers to the weight percentage of the dried, extracted tar sand mineral which passes a fixed mesh size such as 325 mesh (44 microns). The percent fines may be conveniently determined by screening. Figures 8 and 9 summarize a number of analytical results on core samples obtained from test borings in the Great Canadian Oil Sands Lease 86 in the Mildred-Ruth Lakes area. These two figures taken together show the direct correlation of water content with fines, and the inverse correlation of bitumen content with fines. Figure 10 relates bitumen, water, and fines contents from a single test excavation on Lease 86.



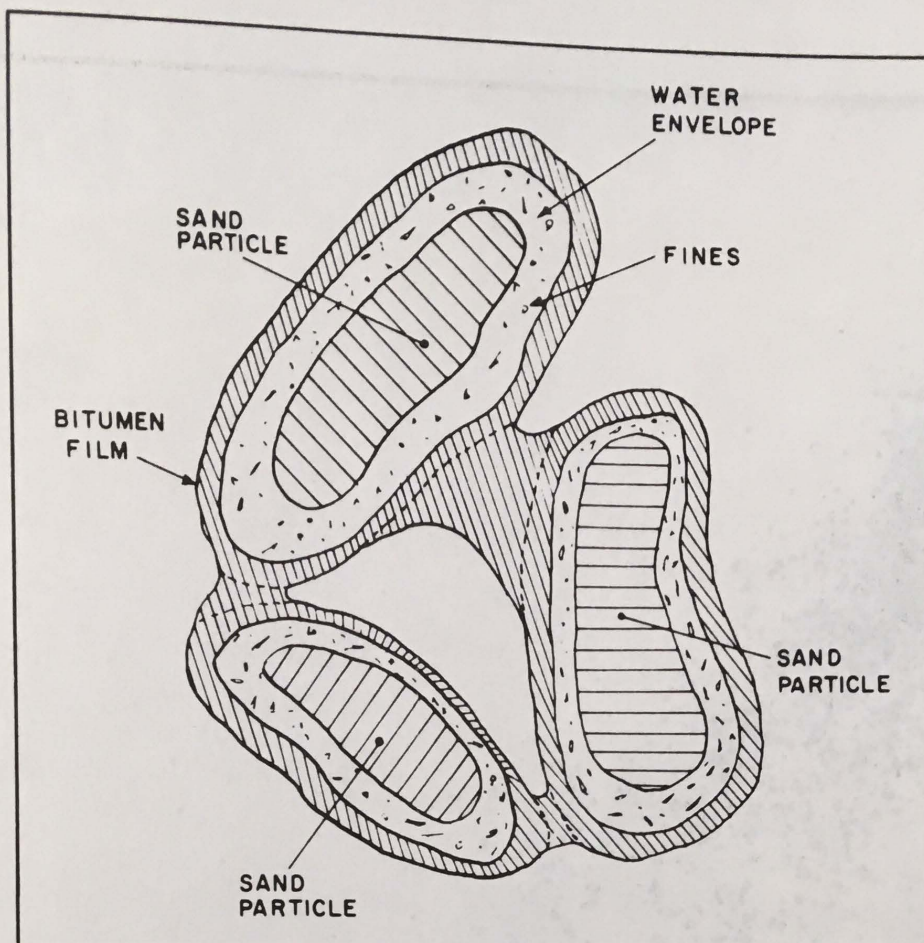


Fig. 7 Typical Arrangement of  
Tar Sands Particles,  
Source, [11]

Compositions and bulk properties of tar sand and tar sand-water mixtures may conveniently be represented using triangle diagrams, as shown in Figures 11, 12, and 13. In Figure 11 the three vertices represent, respectively, 100 wt. % bitumen, mineral, and water. Typical compositions for tar sand, and for various streams encountered in the hot water processing of tar sand, are summarized by the circled areas in Figure 11. Figure 11 is directly superimposable on Figure 12, which is a chart of densities calculated from values for bitumen, water, and mineral at 190°F. The term percent solids, introduced in Figure 12, is defined as 100 minus the percent water. Figure 11 is also superimposable on Figure 13, which represents the heat capacities of tar sand-water mixtures. This chart is based on heat capacities of 1.0, 0.35, and 0.2 BTU/lb.-°F for water, bitumen, and the tar sand mineral (quartz), respectively. Table 2 summarizes a number of values of other bulk properties of tar sands.



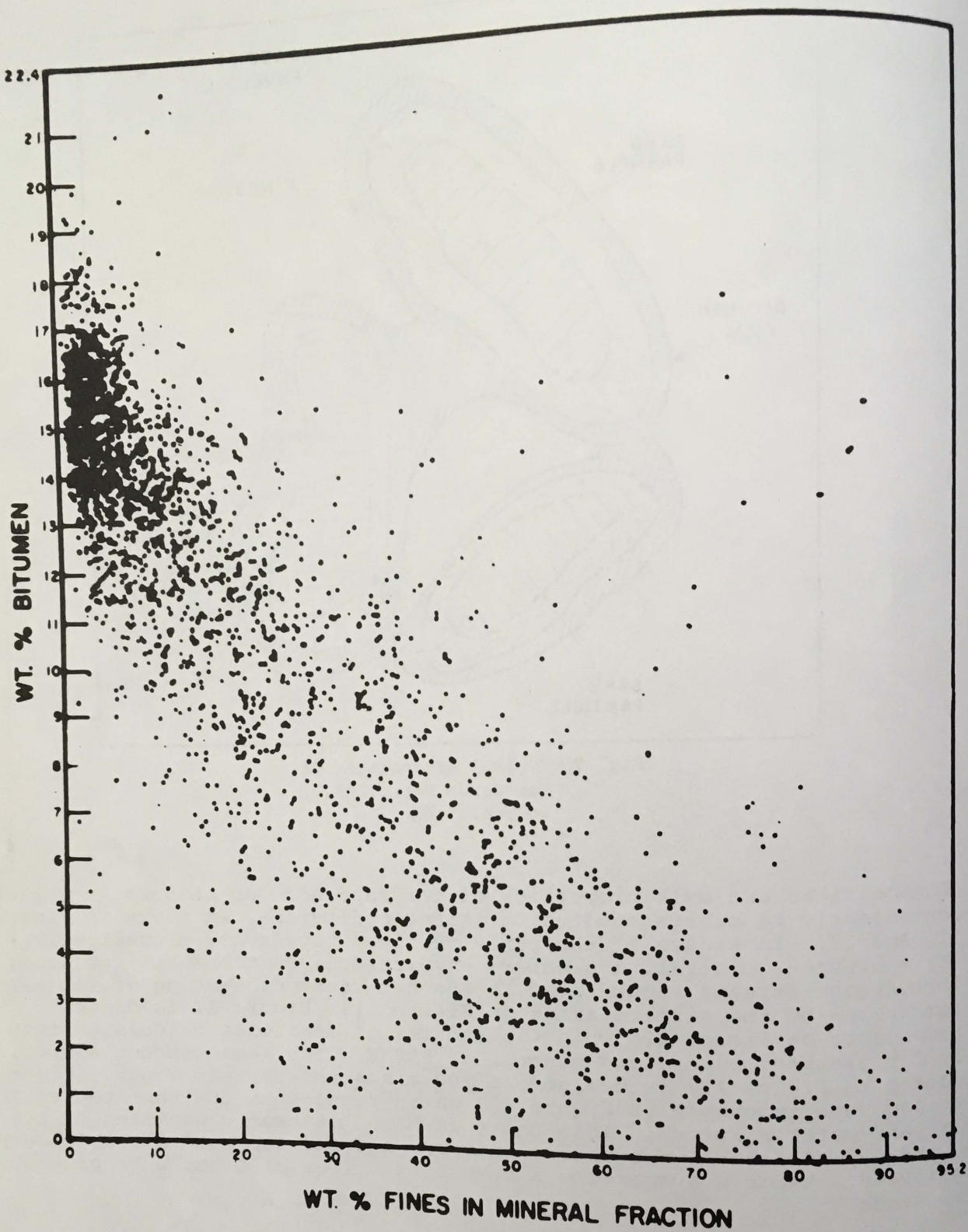


Fig. 8 Core Analysis Data: Relationship of Bitumen Saturation to Fines Content of the Total Mineral Source, [14]



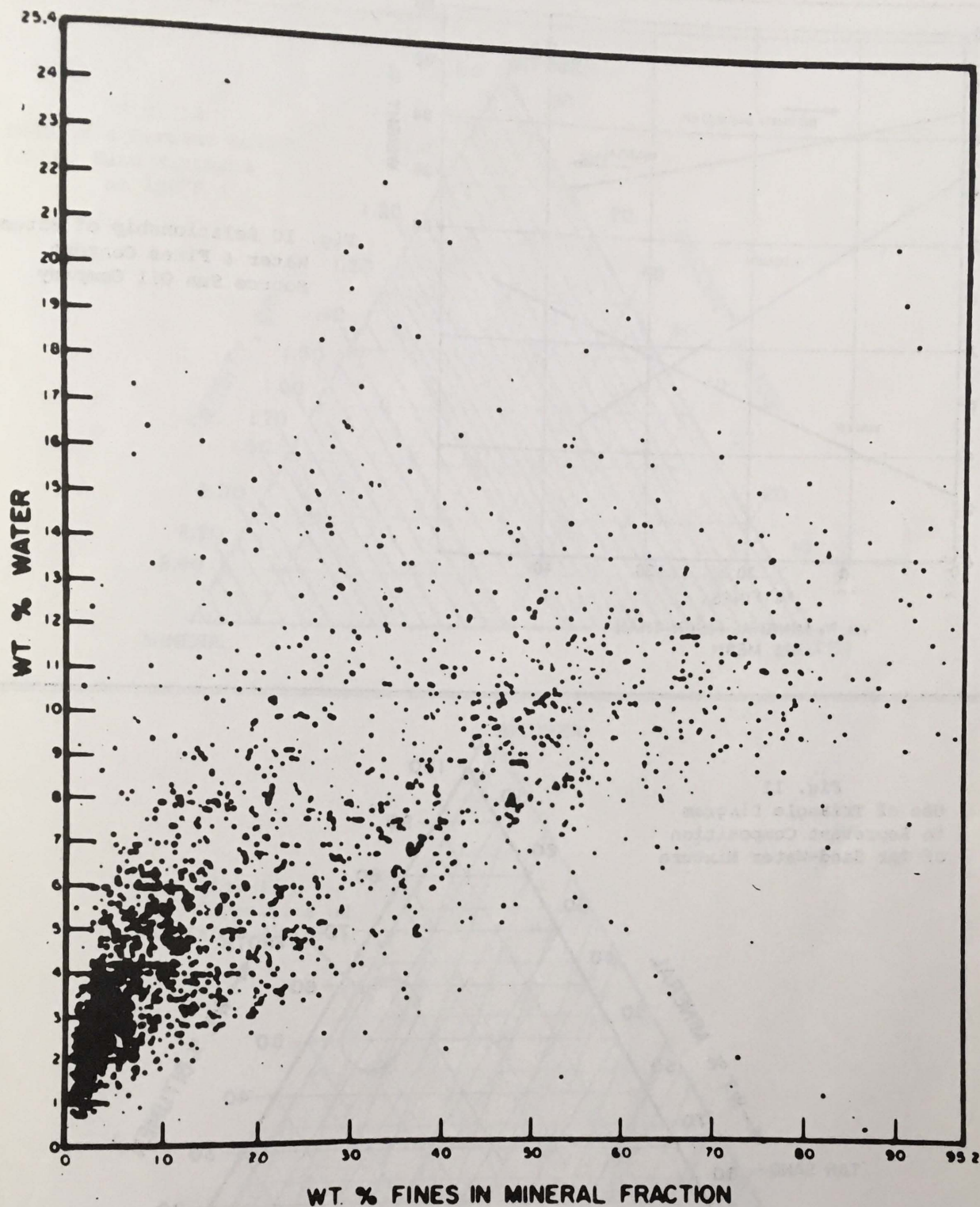


Fig. 9 Core Analysis Data: Relationship of Water Content to Fines Content of the Total Mineral Source, [14]



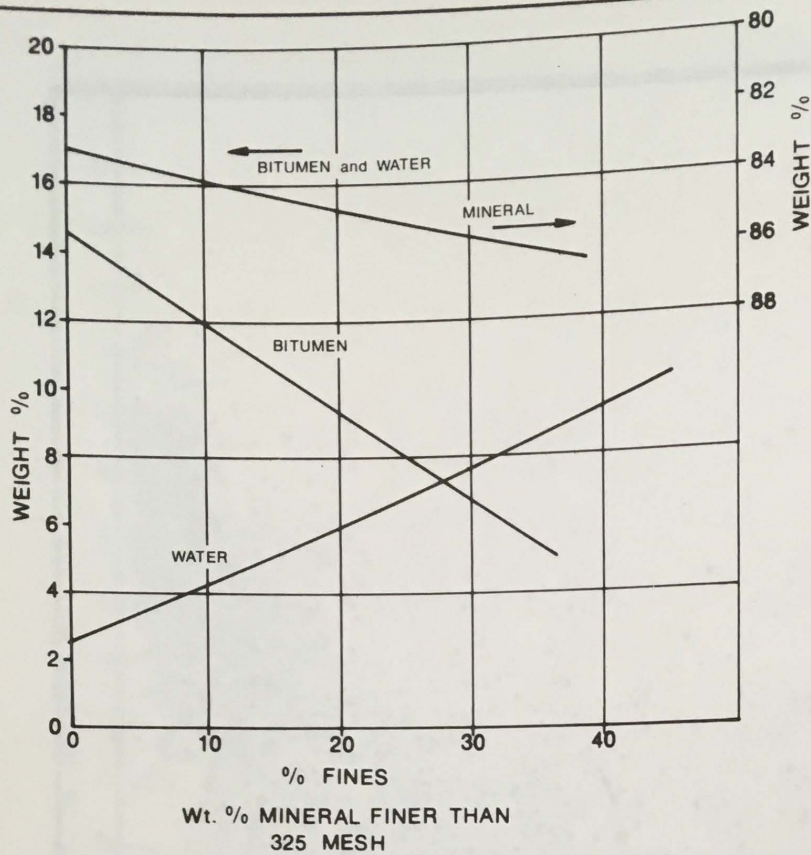


Fig. 10 Relationship of Bitumen, Water & Fines Content, Source Sun Oil Company

Fig. 11  
Use of Triangle Diagram  
to Represent Composition  
of Tar Sand-Water Mixture

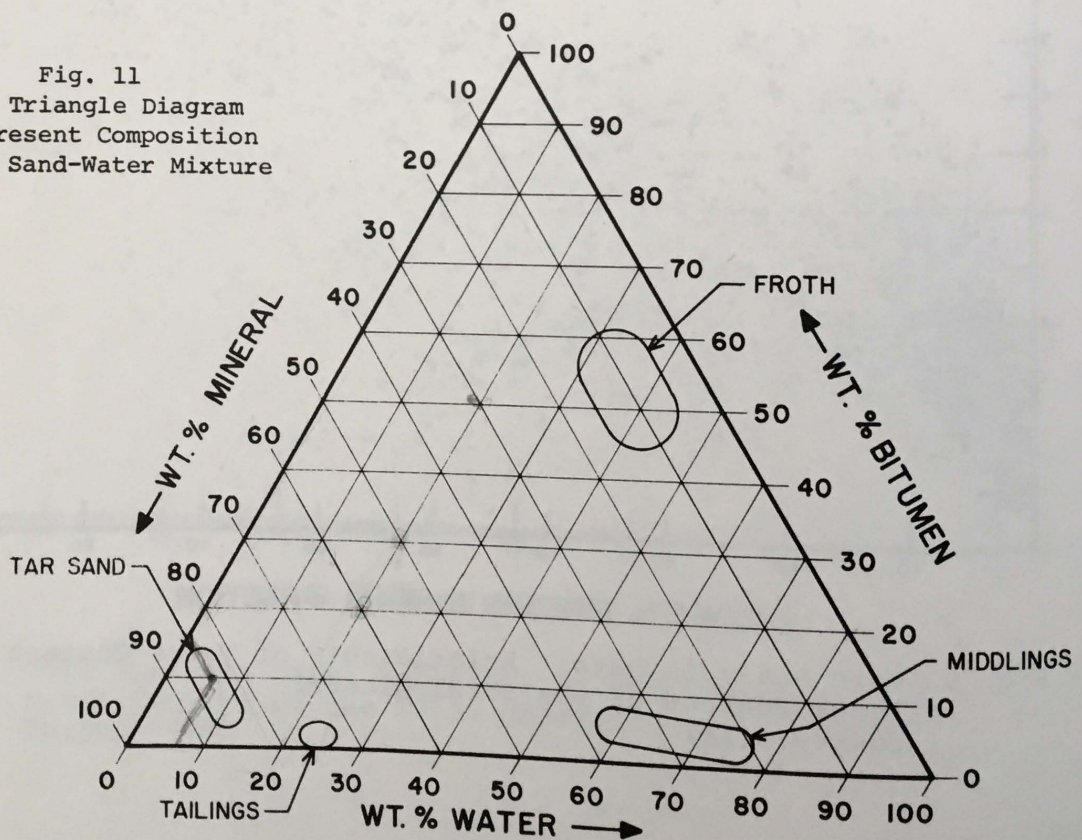




Fig. 12  
Density & Percent Solids  
of Tar Sand Mixtures  
at 190°F

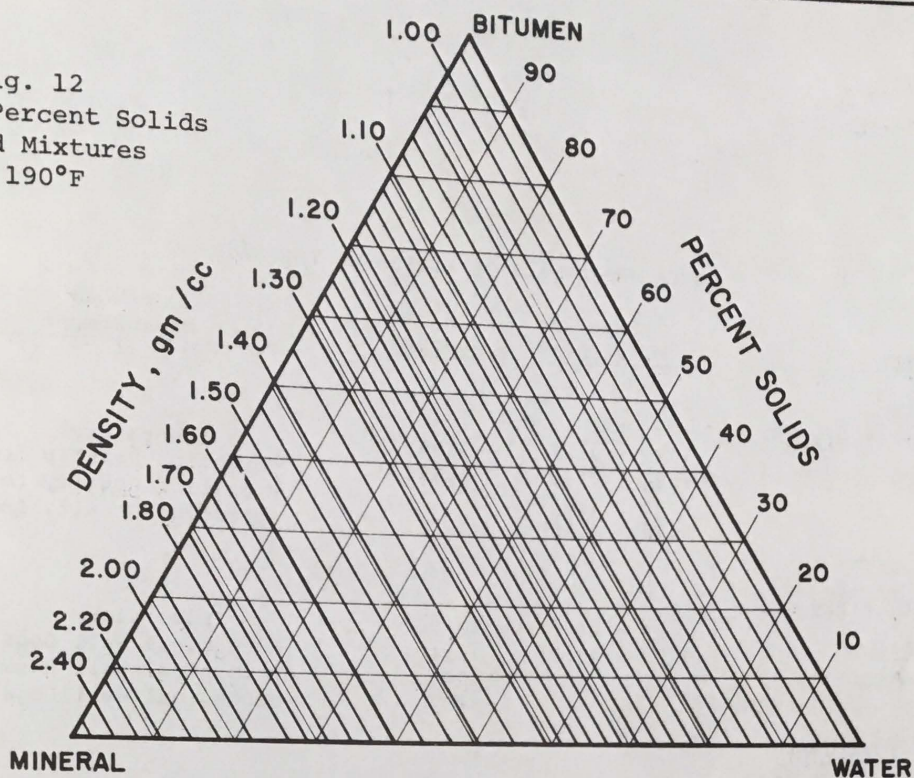


Fig. 13  
Heat Capacities of  
Tar Sands Mixtures

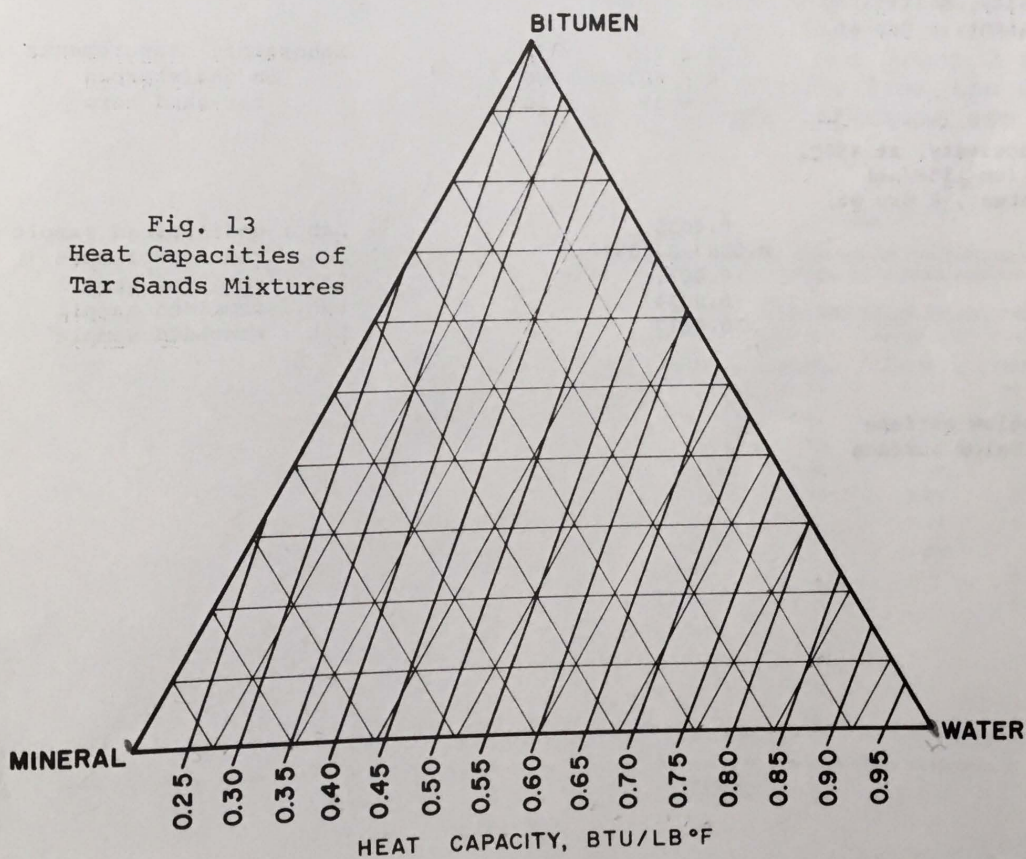




TABLE 2  
BULK PROPERTIES OF ATHABASCA TAR SAND

Property	Range of Values	Average	Method of Measurement	Source: Reference Number
Bulk density, g/cm <sup>3</sup>				
bitumen content, % dry wt.			Laboratory	15
>10	1.75 - 2.09	1.90	Formation Density Log	15
unknown	1.86 - 2.36	1.972	Formation Density Log	15
unknown	1.98 - 2.08 <sup>a</sup>		Formation Density Log	15
unknown	2.10 - 2.19 <sup>b</sup>		Formation Density Log	15
Porosity, vol %				
bitumen content, % dry wt.			Laboratory	15
>10	34 - 46	40.7	Mechanical Well Logs	15
unknown	17.6 - 43.3	31.4	Mechanical Well Logs	15
unknown		40 <sup>a</sup>	Mechanical Well Logs	15
unknown		34 <sup>b</sup>	Mechanical Well Logs	15
Specific heat, cal/(g)(°C)				
bitumen content, % dry wt.				
100		0.35	Laboratory	16
Air permeability, millidarcy				
bitumen content, % dry wt.				
>10	0 - 215	50	Laboratory measurements	15
4-10	0 - 600	100	on undisturbed	15
<4	0 - 35	10	tar-sand core	15
Thermal conductivity, at 45°C, cal/(sec)(cm <sup>2</sup> )(°C/cm)				
bitumen content, % dry wt.				
17.1	0.0035		Lab.; undisturbed sample	16
17.1	0.0027-0.0032		Lab.; remolded sample	16
11.7	0.0021		Lab.; remolded sample	16
8.6	0.0024		Lab.; remolded sample	16
3.0	0.0017		Lab.; remolded sample	16

<sup>a</sup>200 feet below surface

<sup>b</sup>1000 feet below surface



## PROPERTIES OF TAR SAND MINERALS

Table 3 summarizes elemental analyses of tar sand solids by several authors. In the usual case, more than 99% of the tar sand mineral is accounted for by the quartz sand and the clays. Table 4 summarizes minerals which have been found in the sand and in the clay fractions of the tar sand solids. Sand ranges from the largest grains commonly found in the tar sand (99.9% is finer than 1000 micron) down to 44 microns. This size is 325 mesh and is the smallest size which is practical to determine by screening. Mineral sized between 44 microns and 2 microns is referred to as silt. Mineral sized below 2 microns (equivalent spherical diameter) is clay. Clays are aluminosilicates. However, as used here and below, clay is only a size classification and is usually determined by a sedimentation method. According to the previous definition of fines, the fines fraction equals the sum of the silt and clay fractions.

Based on the sieve analyses of the tar sand mineral from a number of core samples, Carrigy described [18] three classes of tar sands with respect to their particle size distribution. These are shown in Figures 14, 15, and 16. The largest of the sands, Group 1, are typical of the bottom of the McMurray Formation (average particle diameter is 150-600 microns; fines content is less than 10%). Sands of smaller median diameter (85-180 microns) but still with low fines content (2-10%) are typical of the middle of the McMurray Formation; these are called Group 2. Sands in Group 3, typical of the top of the formation, have the smallest median diameter (44-110 microns) and a much larger (10-60%) fines content. Superimposed on Figures 14-16 are sieve analyses of tar sand samples taken from three geographical locations in the Athabasca deposit. The largest grained of these sands are from Bitumount (Figure 14). These appear to be a mixture of Group 1 and Group 2 sands. Samples from Ells River, Abasand, and a low-fines sample from the GCOS Lease 86 are all represented by the Abasand line in Figure 15; these are typical of Group 2 sands. Figure 16 shows a GCOS sample of higher fines content which is clearly a Group 3 sand. Group 3 sands have the least oil content of the three. The Group 2 sands are the richest, averaging (among Carrigy's samples) about 14% bitumen. Group 1 sands are slightly less rich, averaging about 12% bitumen, possibly because of some leaching of the relatively porous bottom portion of the tar sand deposit.

Note that Carrigy's classifications refer to a vertical subdivision of the McMurray formation, whereas in Figures 14-16 samples from different geographical areas have been superimposed. This does not imply that Group 1 sands are found only in the Bitumount area. Figure 17 shows in detail the wide range of particle size distributions observed for a number of samples from a single test

TABLE 3  
ELEMENTAL ANALYSIS OF TAR SAND SOLIDS  
AS REPORTED BY VARIOUS AUTHORS

Element	% wt. Reported by Various Authors				
	Syncrude	Nagy and Gagnon	Bowles and Booth	Boyd and Montgomery	Ells
Si		43.14	45.92	50	44.60
Al		2.54	0.42	1.5	1.19
Mg	0.14	0.04	0.12	0.006	0.14
Ca	0.16	0.00	0.14	0.015	0.36
Fe	0.54	0.33	0.07	0.07	0.24
Ti	0.21		0.06	0.05	
Zr	0.05		trace		
Mn				0.005	
Cu				0.0025	
C	0.68				
H	0.18				
N	0.024				
S	0.14				

Source: Bowman (17). Bowman gives reference to the original literature.



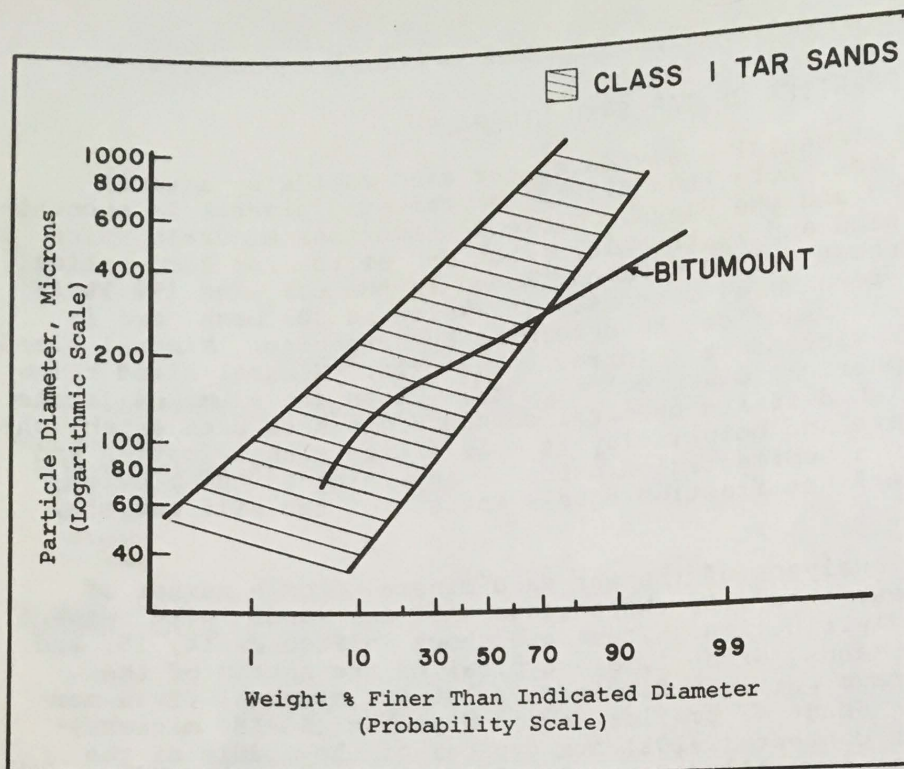
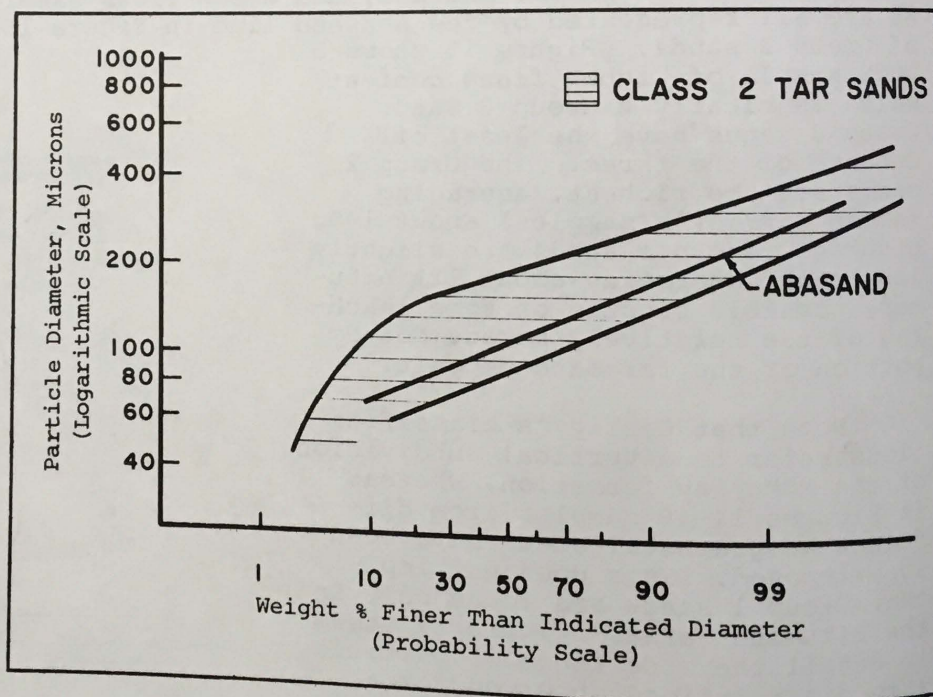


Fig. 14 Tar Sand Particle  
Size Classification  
Class 1

Fig. 15 Tar Sand Particle  
Size Classification  
Class 2





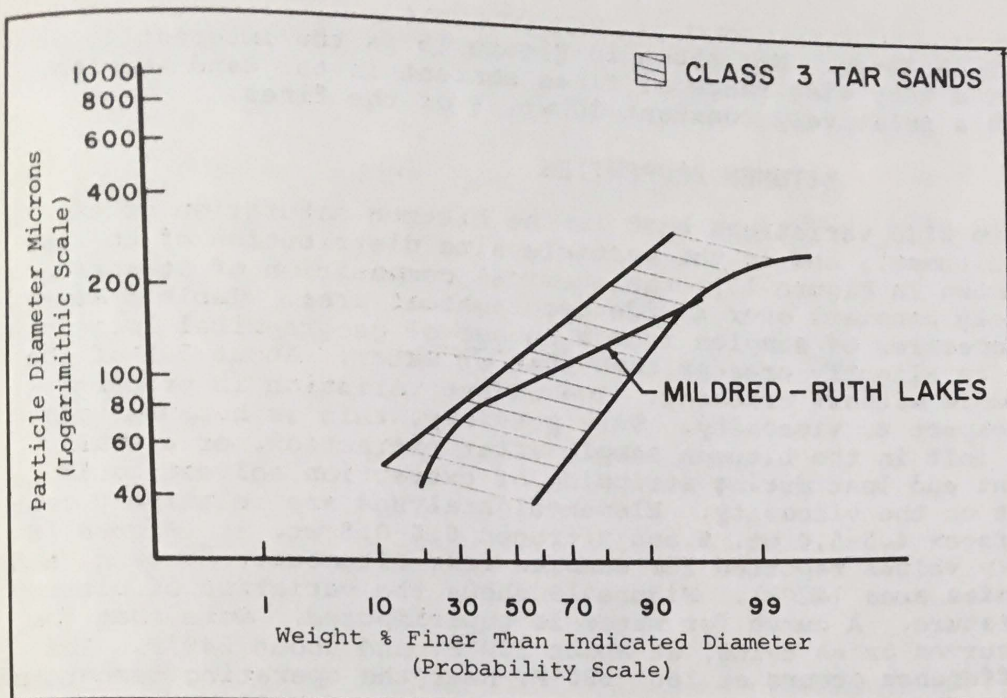
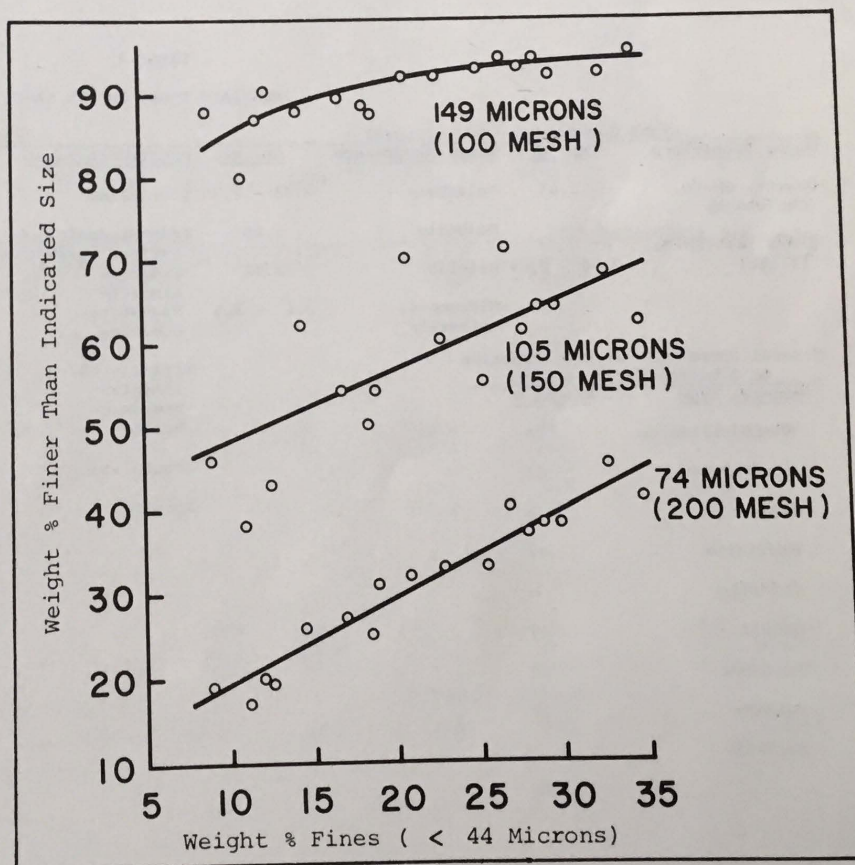


Fig. 16 Tar Sand  
Particle Size  
Classification,  
Class 3

Fig. 17 Range of Particle Size  
Distributions From Test  
Excavation on Lease 86





excavation on the GCOS lease. Not shown in Figure 15 is the interesting observation that over a very wide range of fines content in tar sand samples, the clay portion is a relatively constant 30 wt. % of the fines.

### BITUMEN PROPERTIES

While there are wide variations both in the bitumen saturation of tar sands (0-18 wt. % bitumen), and in the particle size distribution of the tar sand mineral (as shown in Figure 17), the chemical composition of Athabasca bitumen is relatively constant over a wide geographical area. Table 5 summarizes bitumen properties of samples from a number of geographical locations. The density (60°F) is slightly greater than that of water. About 50% of the bitumen is distillable without cracking. The widest variation in properties reported is with respect to viscosity. Very possibly, this is because small amounts of solvent left in the bitumen sample after extraction, or a small portion of the front end lost during stripping of extraction solvent could have a large effect on the viscosity. Elemental analyses are relatively constant. Sulfur averages 4.5-5.0 wt. % and nitrogen 0.4-0.5 wt. %. Figure 18 summarizes viscosity values reported for samples from Bitumount, Abasand, and the Mildred-Ruth Lakes area (GCOS). Figure 19 shows the variation of bitumen density with temperature. A curve for water is superimposed. Note that the water and bitumen curves cross twice, at about 100°F, and about 240°F. The maximum density difference occurs at 160°-180°F, near the operating temperature of the hot water bitumen extraction process.

TABLE 4  
MINERALS FOUND IN TAR SAND

Light Components - 99% of total				Heavy Components - 1% of total			
Major Occurrence	Sp. gr.	Minor Occurrence	Sp. gr.	Major Occurrence	Sp. gr.	Minor Occurrence	Sp. gr.
Quartz, Chert, Chalcedony	2.65	Feldspars	2.54 - 2.76	Tourmaline	3.0 - 3.25	Corundum	4.02
		Dolomite	2.85	Iron minerals:		Garnet	3.5 - 4.3
Clays (Kaolinite, Illite)	2.6 - 2.69	Calcite	2.72	Pyrite, pyrrhotite	4.58 - 5.02	Kyanite	3.56 - 3.66
		Micaceous Minerals	2.6 - 3.5	Siderite	3.83 - 3.88	Apatite	3.15 - 3.20
				Limonite	3.6 - 4.0		
				Magnetite	5.18		
				Hematite	5.26		
						Magnesite	3.0 - 3.2
Mineral Components of Clay Fraction (< 2 micron particle size)				Titaniferous:		Andalusite	3.16 - 3.20
Mineral type	Weight %			Ilmenite	4.7		
Montmorillonite	9			Leucokene			
				Rutile	4.18 - 4.25	Zoisite	3.3
Mixed Layer	11			Staurolite	3.65 - 3.75	Sillimanite	3.23
Illite	10			Epidote	3.35 - 3.45	Pyroxenes	3.15 - 3.55
Kaolinite	22					Amphiboles	2.85 - 3.2
Chlorite	5					Spinel	3.6 - 4.0
Quartz	19					Rhodochrosite	3.45 - 3.6
Feldspar	10					Chalcopyrite	4.1 - 4.3
Calcite	7					Bornite	5.06 - 5.08
Dolomite	7					Cassiterite	6.8 - 7.1
	100						



TABLE 5  
PROPERTIES OF ATHABASCA BITUMEN FROM VARIOUS SOURCES

Inspection	Mildred-Ruth Lakes		Sample No.		Shell Canada Ltd.	Clear- Water River	Ells River	From Ft. McMurray	
	1	2	3	4				75 miles South	120 miles West
Gravity, °API	-	6.5	8.3	8.6	7	-	-	-	-
Sp. Gr., 60/60 °F	1.006	-	-	-	-	-	-	-	-
Dist. Temp., °F	-	-	-	-	-	-	1.007	1.006	1.022
ibp	-	505	-	-	-	-	-	-	-
5%	-	544	-	-	-	-	-	-	-
10%	-	610	-	430	575	-	-	-	-
30%	-	795	-	560	660	-	-	-	-
50%	-	981	-	820	840	-	-	-	-
end pt.	-	1030	-	1010	965	-	-	-	-
Recovery, %	-	50	-	-	-	-	-	-	-
Viscosity SUS/100°F	-	35,100	-	17,533 <sup>1/</sup>	-	-	-	-	-
CS/100°F	-	-	4,993	-	35,000	-	-	-	-
SUS/210°F	-	513	-	-	-	-	-	-	-
Molecular Weight	-	-	539	-	-	-	-	-	-
Elemental Analysis, wt. %									
carbon	83.4	83.2	83.12	-	-	83.6	83.3	83.4	82.9
hydrogen	10.4	10.4	10.59	-	-	10.3	10.4	10.4	10.3
oxygen	1.2	0.94	1.14	-	-	0.2	1.3	0.9	0.9
nitrogen	0.5	0.36	0.40	0.29	-	0.4	0.4	0.6	0.5
sulfur	4.5	4.2	4.75	4.4	-	5.5	4.6	4.7	5.4
Metals, ppm									
vanadium	-	250	290	-	-	-	-	-	-
nickel	-	100	82	-	-	-	-	-	-
iron	-	-	75	-	-	-	-	-	-
copper	-	5	2	-	-	-	-	-	-
Hydrocarbon Type, wt. %									
asphaltenes	-	19	-	-	-	-	-	-	-
resins	-	32	-	-	-	-	-	-	-
oils	-	49	-	-	-	-	-	-	-
Carbon Residue, wt. %	-	10 <sup>2/</sup>	-	13.6 <sup>3/</sup>	-	-	17,690	17,870	17,700
Heating Value, Btu/lb	17,810	-	-	-	-	-	[19]	[19]	[19]
Data Source	[19]	[14]	[17]	[20]	[21]	[19]	[19]	[19]	[19]
Inspection	Abasand Sample No.				5	6	Bitumount Sample No.		
	1	2	3	4			1	2	3
Sp. Gr., 60/60 °F	1.027	1.031	1.027	-	-	1.022	1.007	-	-
Viscosity CS/100 °F	-	-	500,000	-	-	-	-	-	-
Molecular Weight	800	600-700	-	-	-	-	-	-	-
Elemental Analysis, wt. %									
carbon	83.1	81.9	-	-	83.3	83.0	83.3	-	-
hydrogen	10.28	9.5	-	-	10.4	10.2	10.4	-	-
oxygen	1.36	2.9	-	-	0.8	2.5	1.2	-	-
nitrogen	0.30	0.4	-	-	0.4	0.5	0.4	-	-
sulfur	4.96	5.3	-	-	5.1	3.8	4.7	-	-
Metals, ppm									
vanadium	210	-	-	-	-	-	-	-	-
Hydrocarbon Type, wt. %									
asphaltenes	-	-	-	19.5	23.4	-	-	17.9	16-22
resins	-	-	-	32.1	29.0	-	-	34.7	24.8-29.0
oils	-	-	-	47.7	47.6	-	-	45.0	48.2-58.4
Heating Value, Btu/lb	-	-	-	-	-	17,860	17,910	-	-
Data Source	[17]	[17]	[17]	[22]	[19]	[19]	[19]	[22]	[19]
<sup>1/</sup> 130 °F <sup>2/</sup> Ramsbottom <sup>3/</sup> Conradson									



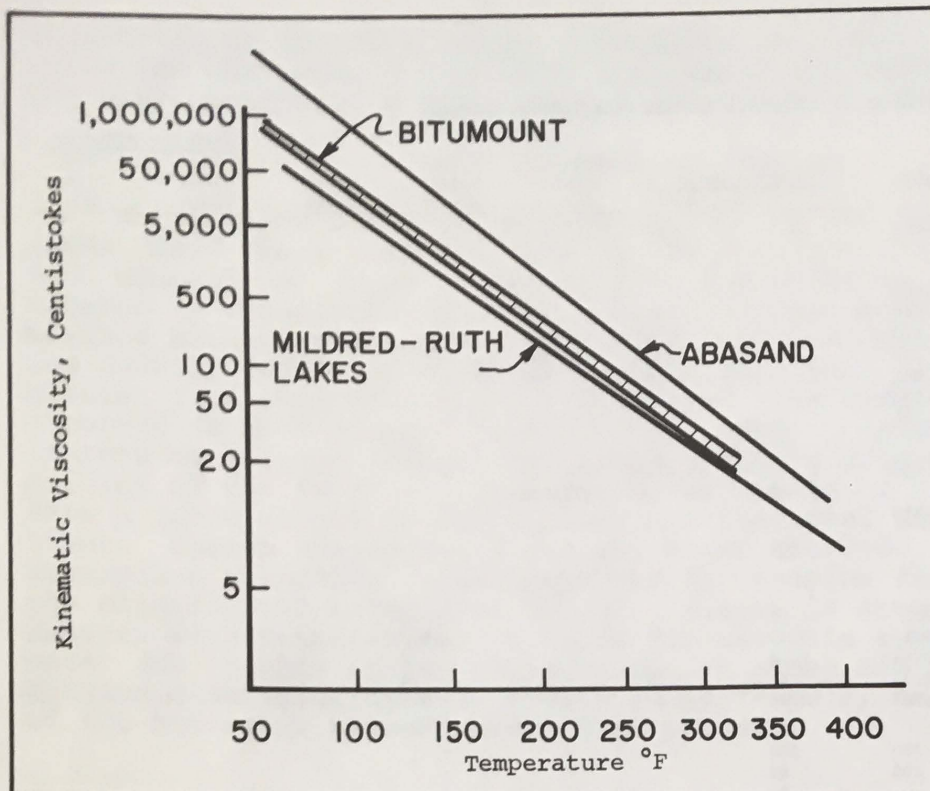
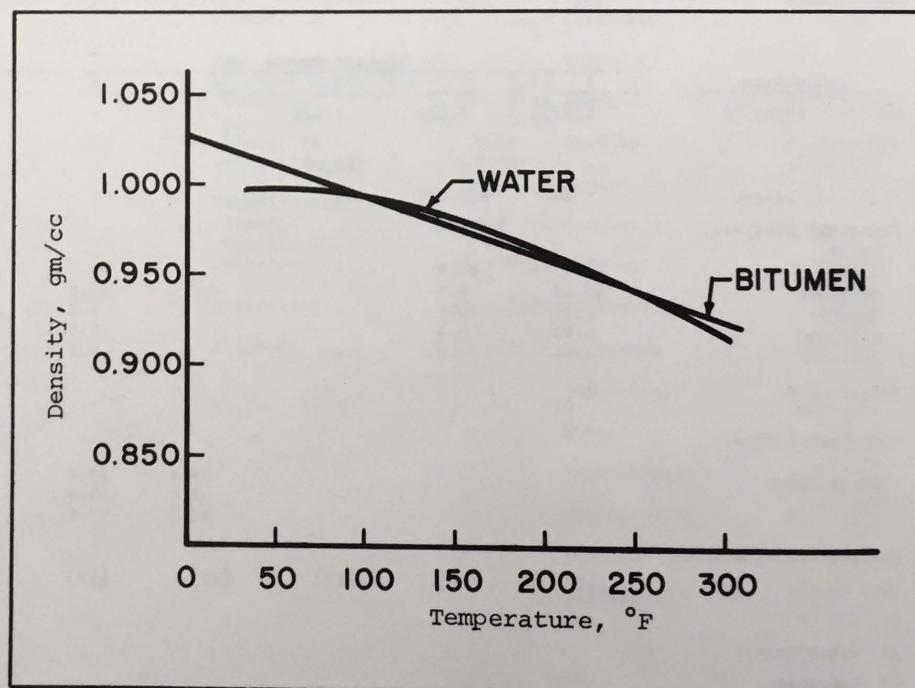


Fig. 18 Bitumen Viscosity

Fig. 19 Density of Bitumen and Water





# PROPERTIES OF REFINED PRODUCTS

Inspections on synthetic crude oils made from Athabasca bitumen by various processes are summarized in Table 6. When the synthetic crude is not desulfurized, sulfur content is about 4%; sulfur and nitrogen removal can be accomplished down to parts-per-million levels. Properties of coke made from Athabasca bitumen are summarized in Table 7.

TABLE 6  
PROPERTIES OF SYNTHETIC CRUDE OIL  
REFINED FROM ATHABASCA BITUMEN

Property	Source of samples							Feed for hydro-treating tests
	GCOS		Cities Service	Shell	Direct fluid coking		UOP <sup>a</sup>	
	Pilot plant	Commercial	Athabasca	Canada, Ltd.	Absand	Bitumount	Pilot Plant	
Gravity, °API	37.6	38.3	30.2	32.8	15.6	15.8	25.5	15.4
Distillation temperature, °F								
ibp	210	162			176	182	118	
5%	277	221			338	412	182	
10%	300	254	265		460	482	245	
30%	379	408	455	400	630	600	438	
50%	486	507	585	540	682	650	550	
90%	680	615		885			750	
end pt	833	715					760	
recovery, %	99						97	
Viscosity								
SUS/150°F			59					
SUS/100°F	34.4			10	52		36.6	66.8
CS/100°F								
Elemental Analysis, wt. %								
carbon	86.3							84.4
hydrogen	13.4							11.2
nitrogen	0.02		0.096	0.09				0.24
oxygen				nil				0.10
sulfur	0.03	0.022	0.182	0.29	4.0	3.9	3.6	4.1
Heavy metals,								
vanadium	0.01							
nickel	0.01							
iron								
copper	0.02							
Hydrocarbon type, wt. %								
asphaltenes	0							
resins	0							
oils (aromatic)	21							
oils (saturated)	79						11.0	
UOP <sup>a</sup> "K"							delayed coking	destructive batch distillation
Process	delayed coking; hydrotreating		fluid coking; hydro-treating	thermal cracking; hydro-treating	direct coking of tar sand @977°F			
Reference	14	23	20	21	22	22	24	25

<sup>a</sup> Source: Sun Oil Company



TABLE 7  
 PROPERTIES OF COKE FROM ATHABASCA BITUMEN

Property	Source and Sample Number			Reference 24
	Sun Oil Company			
	<u>1</u>	<u>2</u>	<u>3</u>	
Proximate analysis, wt. %				
volatile	10.4	14.3	13.0	10.85
fixed carbon	84.3	77.0	82.9	
ash	5.3	8.7	4.1	2.95
Heating value, Btu/lb	14,300	14,000	14,000	
Sulfur, wt. %	6.0	6.0	6.0	6.42



TABLE 7

## PROPERTIES OF COKE FROM ATHABASCA BITUMEN

Property	Source and Sample Number			
	Sun Oil Company			Reference 24
	1	2	3	
Proximate analysis, wt. %				
volatile	10.4	14.3	13.0	10.85
fixed carbon	84.3	77.0	82.9	
ash	5.3	8.7	4.1	2.95
Heating value, Btu/lb	14,300	14,000	14,000	
Sulfur, wt. %	6.0	6.0	6.0	6.42



## TECHNOLOGY OF THE RECOVERY OF VALUES FROM TAR SANDS

There are two basic approaches to recovering bitumen. The tar sand may be mined and transported to a processing plant where the bitumen is extracted and the sand is discharged. Alternatively the separation of bitumen from sand may be accomplished without ever moving the sand, that is, in situ. In situ processes have a great deal in common with secondary recovery of conventional crude oil.

Each of the recovery processes which has been described in the open technical literature is discussed below. A number of additional processes, presently of minor importance, are described in patents [1]. To understand the relative merits, of course, the various processes must be compared. Since the scale of operations described varies from laboratory batch experiments to a 10 ton/hr pilot plant, these comparisons must be made with the greatest care. The term yield or bitumen recovery is subject to so many definitions and possible methods of calculation that comparisons are possibly meaningless. Unfortunately, practically no economic data are available. Despite these shortcomings, process flow sheets may readily be compared. Fundamental process requirements, such as heat, can also be calculated and reliably compared.

### IN SITU PROCESSES

Conventional crude oil is collected (produced) from the oil-bearing formations by drilling wells down into the formation. The oil is driven from the formation up through the wells (production wells) by energy stored in the formation, such as the pressure of natural gas. When this natural energy of formation is expended or, as in the case of the Athabasca tar sands if it the formation is expended or, as in the case of the Athabasca tar sands if it never was present, then energy must be injected into the formation (via injection wells) in order to stimulate production. The third essential for a successful in situ process is a means of communication between the injection wells and the production wells.

#### Thermal Methods of Recovery

In thermal recovery, or fire flooding, energy is generated in the formation in the form of heat. The heat is supplied by actually igniting the oil in the formation, and sustaining it in a state of combustion or partial combustion. The high temperatures generated decrease the viscosity of the oil



and make it more mobile. More importantly, however, the high formation temperatures actually cause coking of the oil, so that an upgraded product rather than bitumen itself is the fluid recovered from the production wells. Thermal recovery processes are referred to as forward combustion and reverse combustion, depending on whether the combustion front moves with (Fig. 20) or counter to (Fig. 21) the direction of air flow. In either case burning occurs at the interface where air contacts hot unburned oil. Thus if the flame front is ignited near the injection well it will propagate toward the production well in forward combustion. However, if the front is ignited near the production well, it will move in the opposite direction. This is reverse combustion. In forward combustion the hydrocarbon products released from the zone of combustion move into a relatively cold portion of the formation. Thus there is a definite upper limit to the viscosity of the liquids which can be recovered by a forward combustion process. On the other hand, since the air passes through the hot formation before reaching the combustion zone, burning is complete; the formation is left completely cleaned of hydrocarbons. In reverse combustion some hydrocarbons are left in the formation. The relative advantage of reverse combustion is that the combustion products move into a heated portion of the formation, and so are not subject to a strict viscosity limitation.

Laboratory tests have been made on reverse combustion in samples of Athabasca tar sands [26]. The tests produced an upgraded oil, amber in color, of 25° API, and 15 cp viscosity. Temperatures and combustion zone velocities observed were a function of the rate at which air was fed to the combustion zone (Figure 22, Figure 23). At air fluxes above 20-40 std cu ft/sq ft hr formation temperatures are in the coking range for Athabasca bitumen (i.e., above 650°F).

#### Combination of Forward Combustion and Water Flood (COFCAW) Process

Field tests of in situ combustion processes, conducted by Pan American Petroleum Corporation, culminated in the development of a combination fire flood-water flood process [55]. In the combination process, forward combustion is used to heat a portion of the reservoir to a peak temperature of 1500°F. Following the heating phase, air and water are injected into the formation. The water serves to dissipate the local high temperature heat, so that a much larger proportion of the reservoir is uniformly heated to about 200°F. At this temperature, the bitumen becomes more mobile and is produced under the action of the air and water drive. The temperature profile is illustrated schematically in Figure 24.

Development of the COFCAW process was begun with laboratory work in 1956. From the lab program it appeared that forward combustion would not be successful, because of the relatively low permeability of the tar sand formation. Reverse combustion appeared a useful possibility. These conclusions were confirmed in field trials conducted in 1958-59. In further field trials between 1960-65, however, a second attempt at reverse combustion failed. At this point it was concluded that the previous tests had been successful because the formation had inadvertently been fractured. Attention was then turned to developing the two step forward combustion-water flood process.

The two step process was the subject of field trials conducted during 1965-68 on the Gregoire Lake Indian Reserve No. 176, 25 miles south of Fort McMurray [56]. A five-spot well pattern was drilled, on a 150 foot square; four production wells were at the corners, with a central injection well.



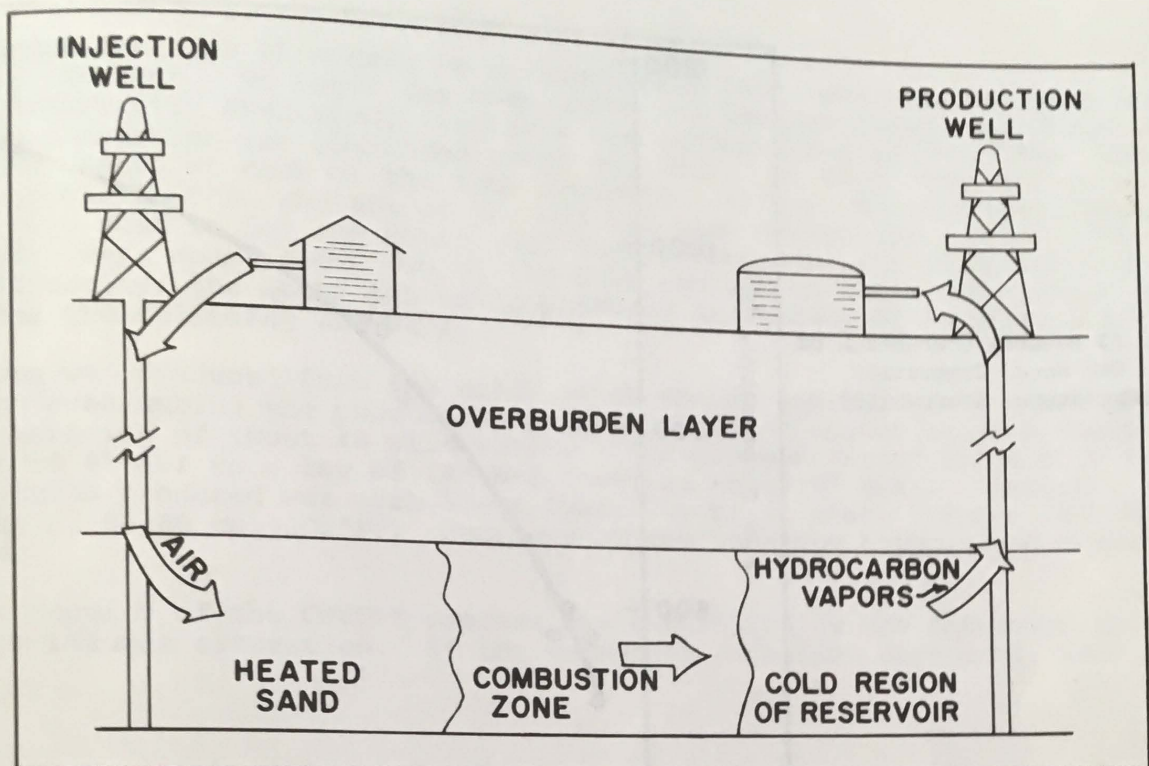


Fig. 20 Forward Combustion - Schematic

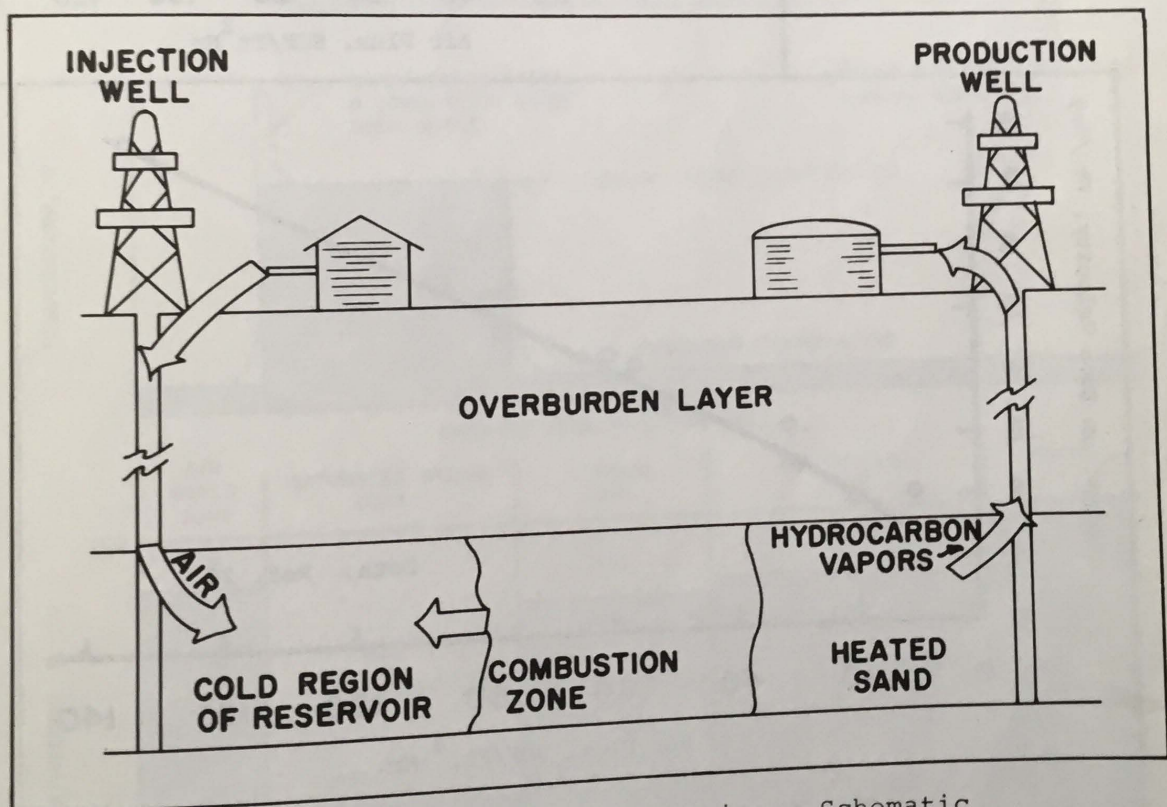


Fig. 21 Reverse Combustion - Schematic



Fig. 22 Reverse Combustion of  
Tar Sands-Combustion  
Temperature, Source [26]

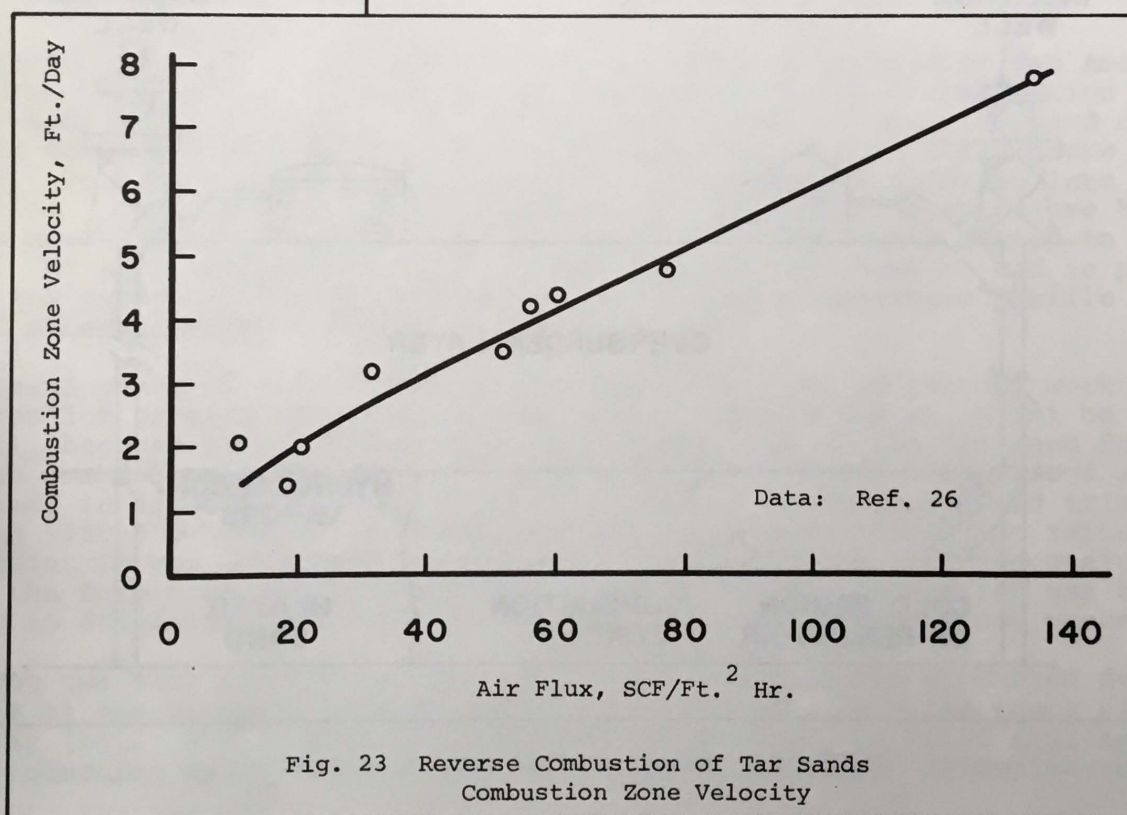
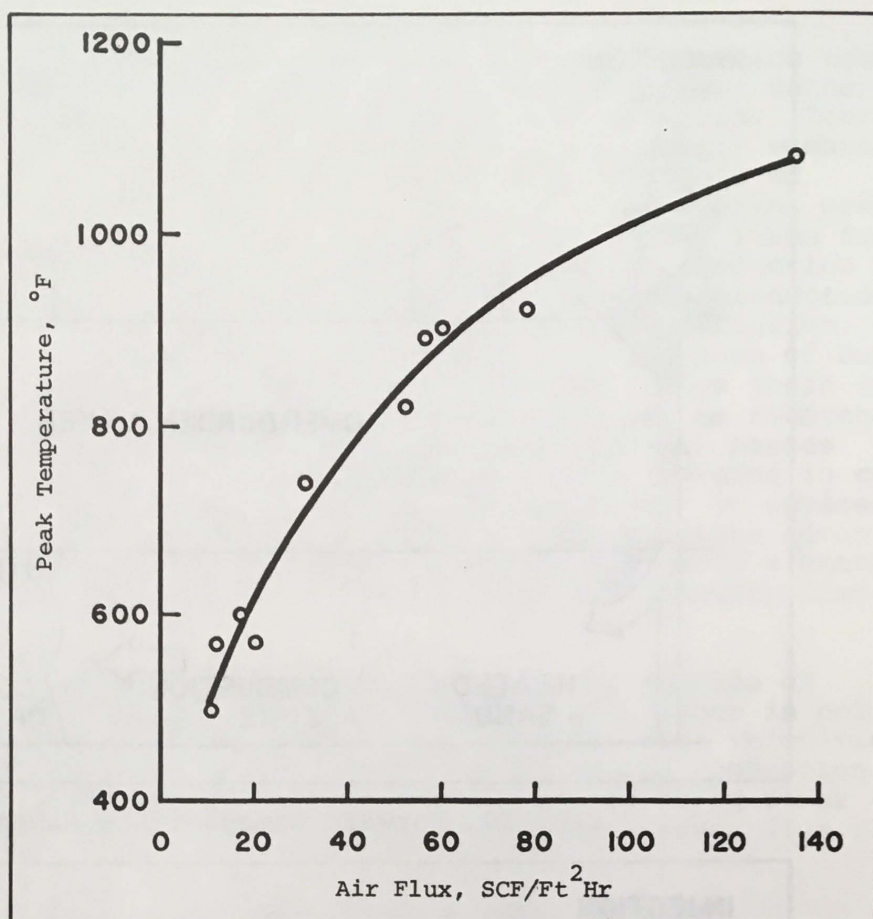


Fig. 23 Reverse Combustion of Tar Sands  
Combustion Zone Velocity

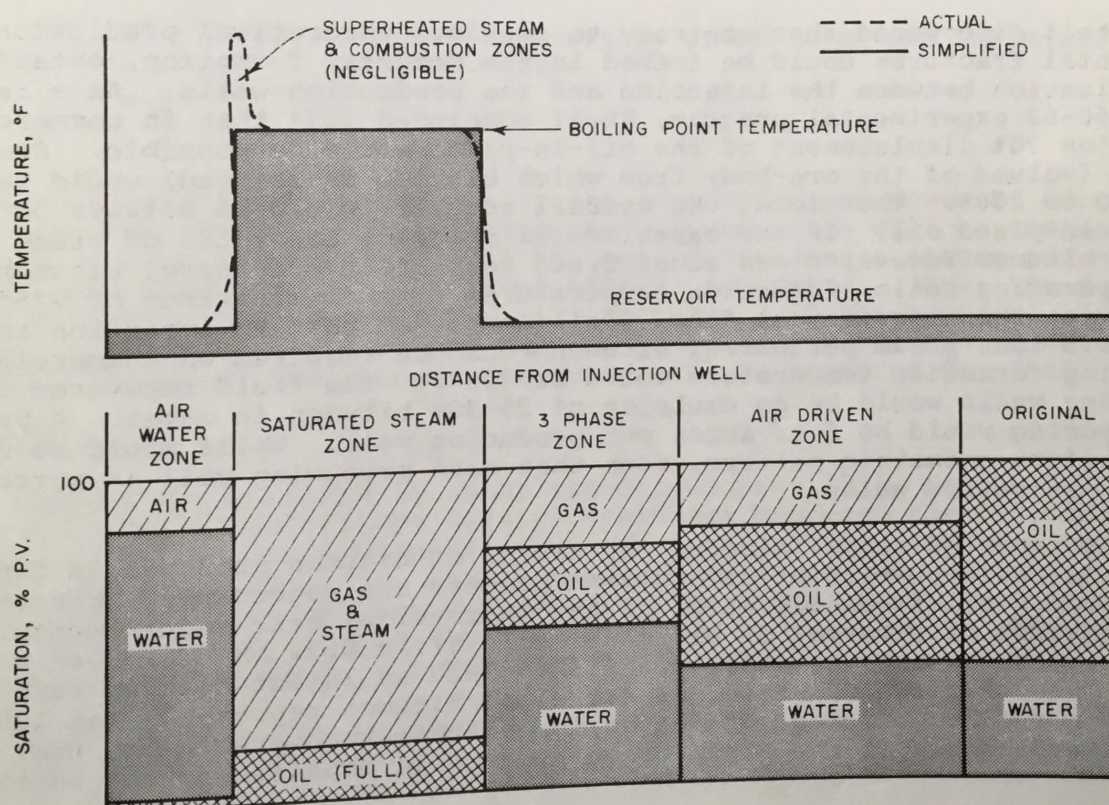


Overburden depth in this area is approximately 1000 feet; the tar sand thickness is 120 feet. To begin the combustion and heating phase, the formation was hydraulically fractured. Ignition was accomplished in July 1966 and forward combustion was continued until May 1967. At this time, the formation had been heated at each of the four production wells. Maximum temperature recorded was 1500°F, and 65% of the oil had been heated above 150°F. The wells were shut in for one month, and then production, air injection and water injection were commenced. Two of the four production wells experienced mechanical difficulty; the other two wells produced an average of 63 barrels per day each for the following 200 days.

Gas was produced from the wells in an amount approximately equal to the air injected during the production phase. Liquid produced was a bitumen-water emulsion of about 40 wt.% water. The bitumen varied in density from a high of 8° API to a low of 14° API (average about 9° API). Viscosity of the bitumen produced was much lower than that of in place bitumen (200-800 cp, 100°F; 50-80 cp, 200°F). Recovery of the in place bitumen was estimated at 55%.

Economics of the COFCAW process are controlled by the formation thickness and the bitumen saturation. As the formation thickness decreases, heat losses

Fig. 24 Schematic Drawing of COFCAW Saturation & Temperature Profiles





to the overburden and to the bed rock increase. At the same time, production per well decreases. Formation thickness of 120 feet, as tested, was considered satisfactory. No estimate of the minimum economic thickness has been given. The effect of bitumen saturation is expressed in the ratio of the amount of air which must be injected during the production phase to the amount of bitumen recovered. An air/oil ratio of about 7000 SCF/BBL corresponds to 12 wt. % bitumen saturation, and is considered a satisfactory value. The lower economic limit is estimated at 20,000 SCF/BBL (40% bitumen).

#### Emulsion-Steam Drive Process

If the viscous bitumen in a tar sand formation can be made mobile by admixture of either a hydrocarbon diluent or an emulsifying fluid, then another relatively low temperature secondary recovery process may be possible. Shell Canada, Ltd. tested an emulsion process in field trials between 1957 and 1962 [27]. Emulsification was preferred to use of a hydrocarbon diluent because: (1) diluent is more expensive than the emulsifying fluid (water); and (2) relatively large amounts of diluent would be required to reduce the viscosity of the very viscous Athabasca bitumen. Viscosity of a bitumen-in-water emulsion (20-30% bitumen) is essentially the viscosity of water.

Field trials were conducted between 1957 and 1959 on use of a proprietary non-ionic surfactant in water. During a somewhat larger and more comprehensive program between 1960 and 1962, a combination caustic solution (NaOH in water) and steam drive technique was tested. For this test, a five spot pattern of wells was drilled, with four injection wells at the four corner of a square, and a centrally located producing well. Figure 25 is a schematic cross section of the experimental arrangement.

Shell discovered that contrary to previous theoretical predictions [28], horizontal fractures could be formed in the McMurray formation, establishing communication between the injection and the production wells. As a result of the 1960-62 experimental program, Shell concluded [27] that in commercial operation 70% displacement of the oil-in-place would be possible. Sweep efficiency (volume of the ore-body from which bitumen is removed) would range from 70 to 100%. Therefore, the overall recovery would be between 50 and 70% of the in-place oil. In the experimental program, the ratio of steam injected to bitumen recovered was about 0.685 tons steam per barrel bitumen. At this operating ratio, formation temperatures reached a maximum of 275°F. Interpreting the experimental data, Shell concluded that an injection rate of about 0.5 tons steam per barrel bitumen would be required on commercial scale. Operating formation temperature would be 350°F. The fluid recovered from the producing wells would be an emulsion of 25-30% bitumen in water. A practical well spacing would be four acres per producing well. Wells would be spotted in a uniform geometric pattern, such that each producing well is surrounded by four injection wells.

The ratio of steam injected per barrel of bitumen produced is important as far as the economics of an emulsion process are concerned. This can be shown from a brief consideration of the theoretical heat requirements. Net heating value of a barrel of bitumen (Table 6) is 6.24 MM BTU. One ton of steam represents approximately two million BTU as latent heat of vaporization. Thus, 1/2 ton of steam per barrel of bitumen represents (at 100% efficiency) a fuel requirement of 16% of the bitumen recovered. If, now, the thermal efficiency of the steam drive process is impaired -- for instance by



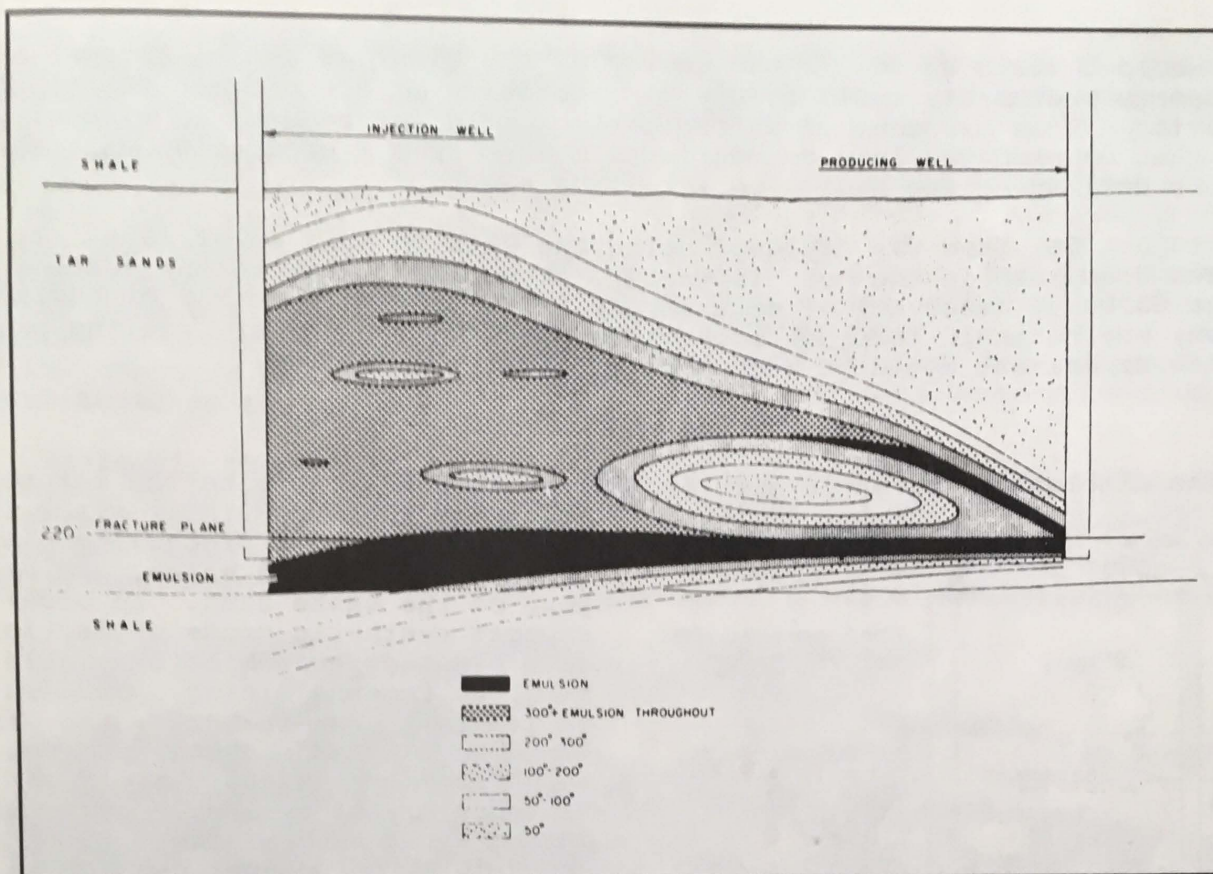


Fig. 25 In-Situ Bitumen Recovery By Steam Injection Schematic  
Source, [28]

heat losses upward in the formation to the overburden, or downward from the formation -- the numerator of the steam to bitumen ratio will be increased. Conversely, as the tar sand grade (% bitumen) decreases, a larger amount of sand must be heated for each barrel of bitumen recovered. Thus, the denominator of the steam to bitumen ratio will decrease. If the expected thermal efficiency is significantly reduced then a relatively large and economically significant amount of the recovered bitumen will be required for fuel.

#### Atomic Explosion

In 1958, a group headed by Richfield Oil Company [29], and including Imperial Oil Limited and Cities Service Athabasca proposed the test firing of an atomic bomb in the Athabasca oil sands. Project Oil Sand was the title of their proposal to the U. S. Atomic Energy Commission (who would supply the nuclear device) and the Oil and Gas Conservation Board of the Province of Alberta. The proposal was given technical study at the time it was made; action has been deferred by the Canadian Government.

The location proposed was Pony Creek, 64 miles south of Fort McMurray. It was planned that a nine kiloton device be exploded at a depth of 1250 feet, as shown in Figure 26. A cavity some 230 feet in diameter would be created,



which would contain up to 1/2 the energy of the blast as useful thermal energy. This energy presumably would reduce the viscosity of the bitumen contained in the cavity. This bitumen, if sufficiently heated and reduced in viscosity, could then be produced in a conventional manner from a production well which would be drilled at the test site after the blast.

Project Oil Sand was designed using the data in hand as of 1958. It has not been discussed in the open literature since 1963. The recent success of Project Gasbuggy (recovery of natural gas in New Mexico by means of nuclear explosion) may rekindle interest in Project Oil Sand. Certainly, at the present time the experiment could be much more critically designed.

## MINING

The alternative to an in situ processing scheme is to mine the tar sands,

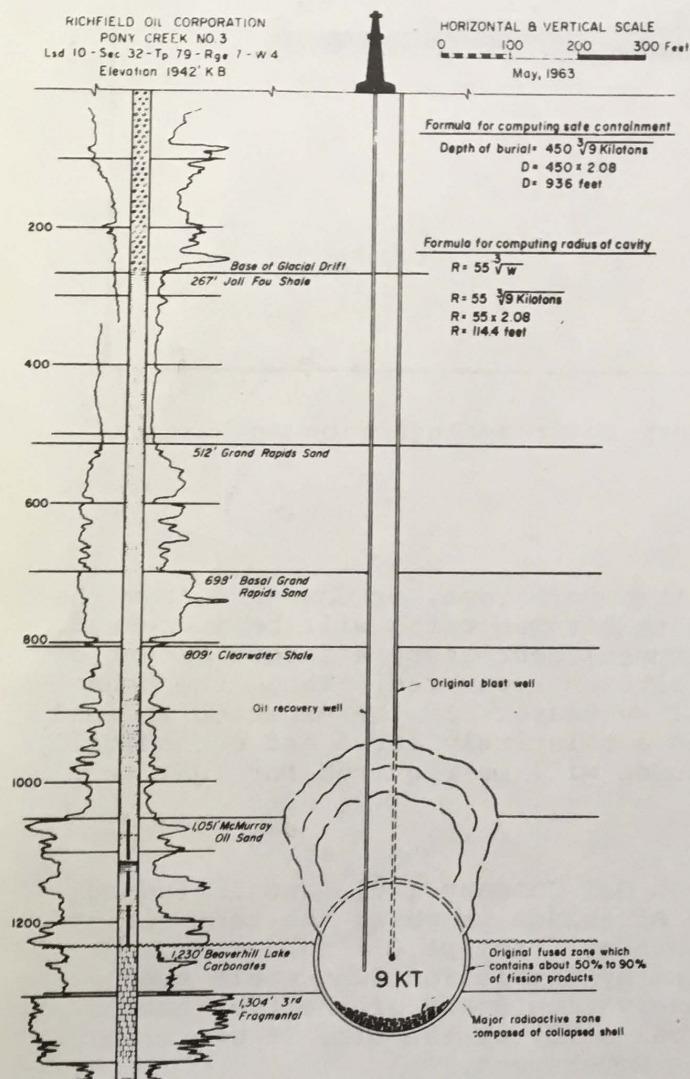


Fig. 26 Proposed Nuclear Test For Bitumen Recovery Source, [29]

transport them from their place in the formation to a processing plant, extract the bitumen value, and dispose of the waste sand. In order to support synthetic crude production in a plant of economically viable size, an immense mining operation is called for. For instance, the Great Canadian Oil Sands (GCOS) project which produces 45,000 barrels per calendar day of synthetic crude requires a tar sand mining rate of about 100,000 tons per day. This figure refers to the tar sand (ore) only, and does not include the overburden which must be stripped away in order to expose the tar sands for mining. This mining rate is of the order of size of the largest mines in North America, such as the open pit iron ore mines of Labrador and Minnesota. Because of the large scale of mining involved, only open pit methods have been proposed for the Athabasca tar sands. As noted above one important parameter of an open pit mining scheme is the overburden ratio (the thickness of overburden which must be scraped away to expose unit thickness of the ore body). For the GCOS project, the overburden ratio is approximately 0.4 [14]. Overburden ratios as high as 2.5-3.5 have been discussed [30], but have not been seriously proposed.

Because of the relatively low unit value of tar sand as an ore, mining and transportation costs must be rigorously minimized. This means, among other things, that the feed must



receive only a minimum amount of handling between the mine and the processing plant. On the other hand, for economy of operation in the processing plant, continuous units must be designed to operate with a relatively steady feed rate, round the clock. Such processing is usual in petroleum refineries; it is very definitely the exception in mining. Thus, quite apart from the large size scale, tar sand mining presents the unique problem of assuring a relatively steady feed rate to the processing plant, round the clock and year round. In addition to this requirement, which is general for any tar sand formation, the Athabasca tar sands present two other significant problems for mining: (1) tar sand in-place requires very large cutting forces and is extremely abrasive to the cutting edges exposed to it; and (2) both the equipment and pit layouts must be designed to operate during the long Canadian winters at temperatures as low as 60°F below zero.

Basically there are two approaches to the open pit mining of tar sands. The first is to use a few mining units of custom design, which will necessarily be very expensive. For instance, large units which have been considered are bucket wheel excavators, dredges (both hydraulic and bucket ladder) and super-sized draglines. The other approach is to use a multiplicity of smaller

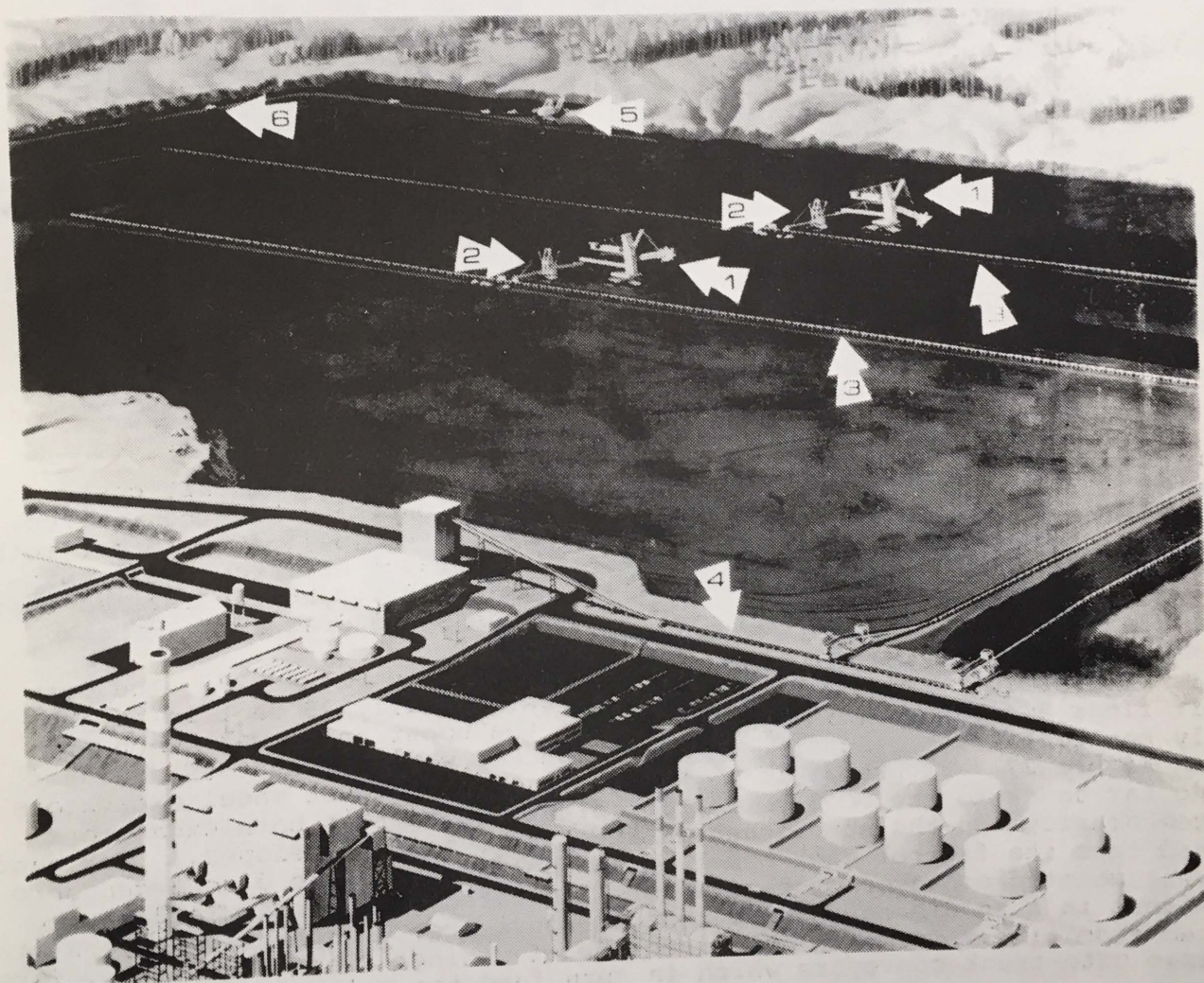


Fig. 27 Artist's Conception of GCOS Mine & Plant





Fig. 28 GCOS Bucketwheel Excavators

mining units of conventional design and relatively much lower unit costs. For example, scrapers and truck-and-shovel operations have been considered. Each method has advantages and its own peculiar risks [30]. The former method has been adopted by GCOS [14, 31]. The latter approach was proposed by Syncrude Canada, Ltd. [32] in 1968; however, in 1971 [58], Syncrude revised their mine plan returning to the use of large custom-designed drag lines.

Main features of the GCOS pit design are shown in Figure 27. The ore body is divided into 2 layers or benches, each nominally 75 feet in height. The pit floor and the dividing plane between the upper and lower bench are roughly horizontal. Mining is done by two bucket wheel excavators, located in 1 in Figure 27. Figure 28 is a photograph of two bucket wheel excavators feeding tar sands to the GCOS Extraction plant. (Note that both excavators are--temporarily--on the same bench as the pit is being developed.) Tar sands loosened from the face of each bench by the bucket wheel are discharged onto a crawler mounted conveyor or belt wagon, indicated at 2 on Figure 27. The belt wagons in turn discharge onto movable conveyors, 3. These conveyors are advanced from time to time in the direction of mining. The movable conveyors discharge onto trunk conveyors which in turn feed the main conveyor, 4.



This conveyor is shown also in Figure 28. Maximum design capacity of each bucket wheel is 9,000 tons/hour, more than enough to feed the entire plant. However, because of uncertainties as to the amount of time required for maintenance and unscheduled shutdowns, it was considered necessary to install two bucket wheel excavators at the outset. The overburden stripping operation, shown in Figure 27 being accomplished by an electric shovel, 5, and off-road trucks, 6, actually is currently being carried out by scrapers.

Main features of the pit design proposed by Syncrude in 1968 [32] are shown in Figure 29. The Syncrude mining operation [30] would be based on scrapers of conventional design, and of approximately 40 cu. yd. capacity per unit. The pit is laid out in two benches and has very roughly a "race track" shape. Central to the pit is a drive-over dump station. The scrapers drive over this station without stopping and discharge their load to a conveyor which moves the tar sand to the plant area. Scrapers are also to be used for overburden stripping. The Syncrude application [32] is for production of 80,000 B/D of synthetic crude and specialty oils which requires a rate of

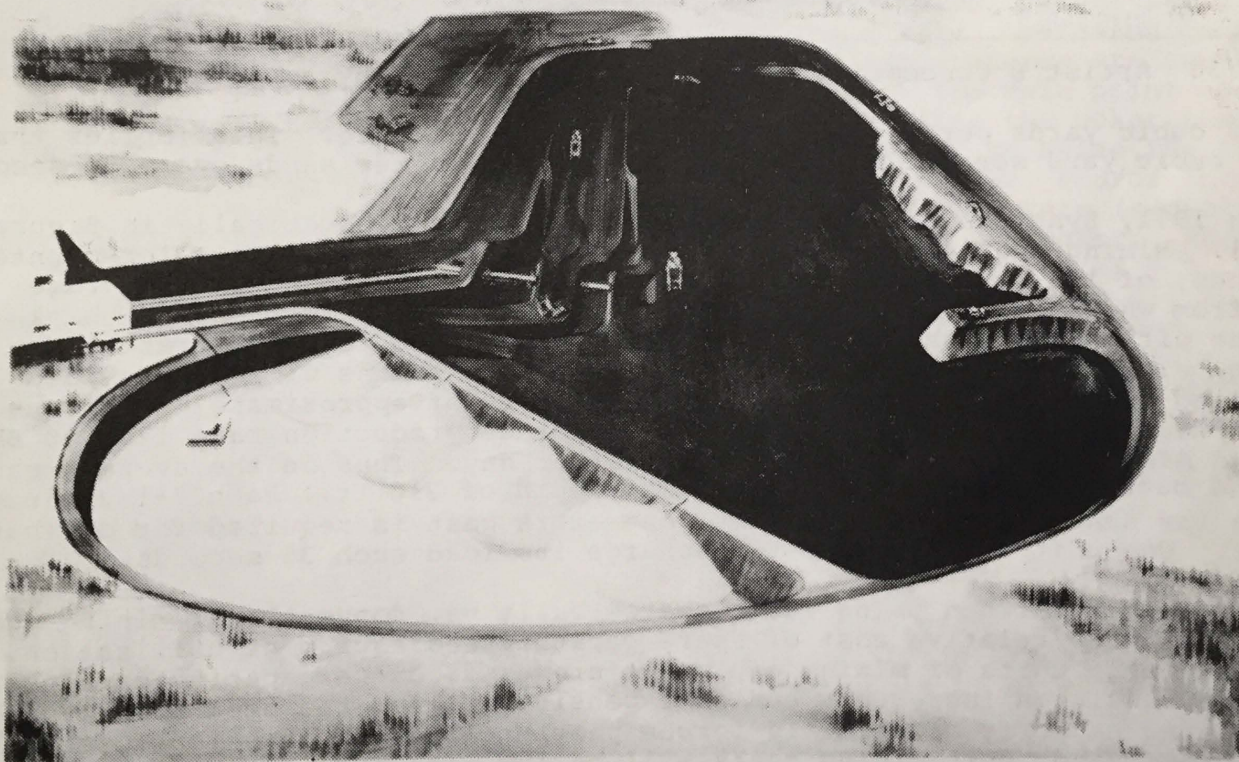


Fig. 29 Artist's Conception of Mining Plan Proposed by Syncrude in 1968



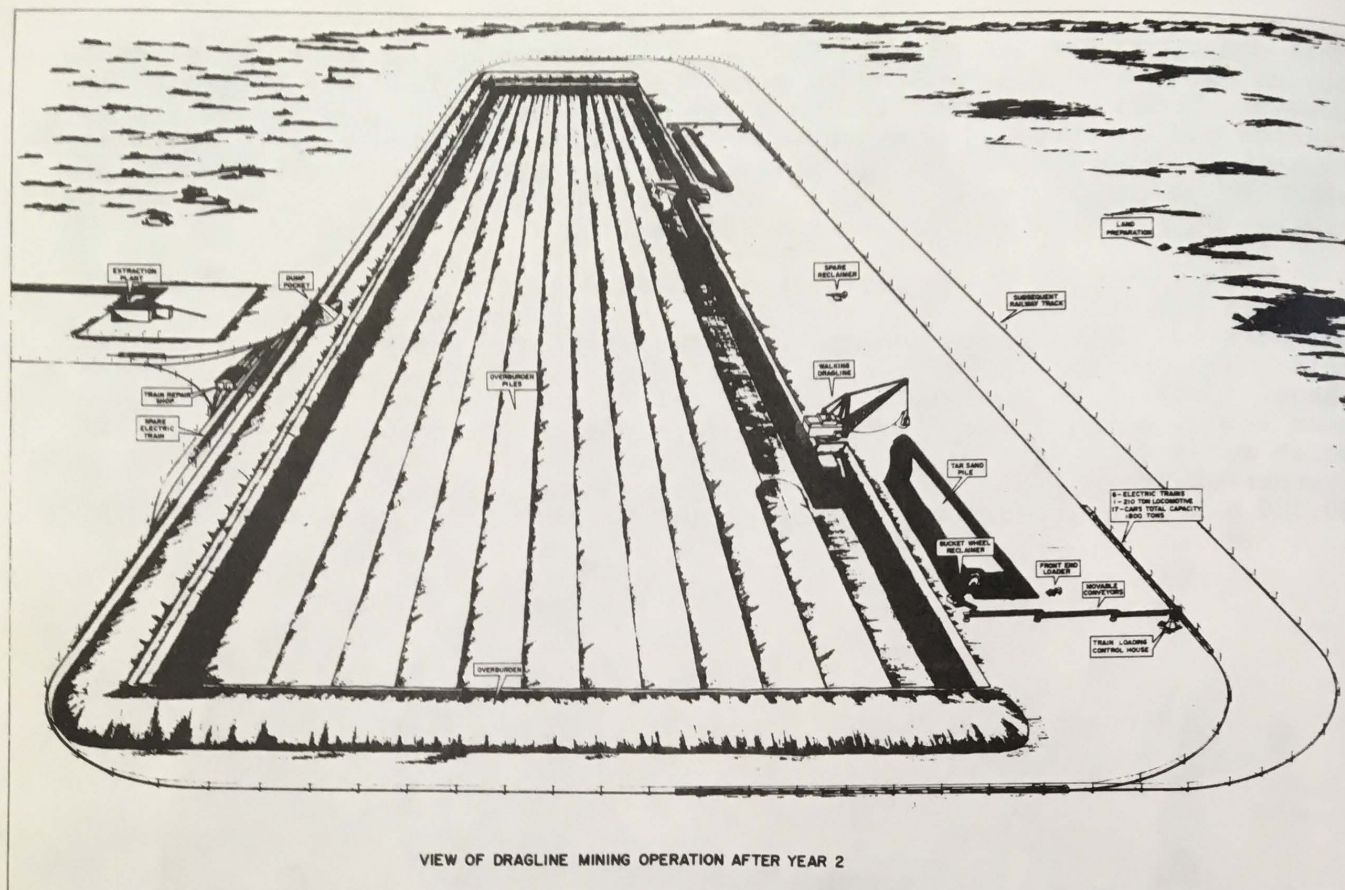


Fig. 30 Artist's Conception of Mining Plan Proposed by Syncrude in 1971

104,000 cubic yards per day, or 72 cubic yards per minute. This implies that one 40 cubic yard scraper must discharge its load of tar sands every 30 seconds.

In 1971, Syncrude proposed the pit design shown schematically in Figure 30 [58]. Mining and overburden removal are done by two giant crawler-mounted draglines, of 130 cu. yd. capacity. Mined tar sand is dumped onto storage piles from which it is reclaimed by bucketwheels. Overburden is cast back into the pit in windrows. The ore is then transported to the extraction plant by electric-powered unit trains. Seven such trains will be provided (including one spare), each consisting of 17 cars of approximately 100 tons capacity each. At the authorized synthetic crude production rate 125,000 BPCD, tar sand mining rate is over 250 tons/calendar day. Thus on the average each dragline must make one cast (to a maximum depth of 210 ft.) each 2-1/2 minutes to mine tar sand. In this same time, one extra cast is required for overburden removal. One unit-train car must discharge its load each 35 seconds.

The choice between using large custom-built vs. conventional mining equipment lies in the relative cost of spare capacity and equipment utilization. When very large units of mining equipment are used, extra capacity necessarily also comes in large increments and is expensive. Thus, the need to provide spare mining capacity practically forces poor utilization of this capacity. On the other hand, unit mining costs will be low with big equipment. Unit mining costs may be expected to be high if smaller mining units are used; however, a few extra scrapers, purchased at relatively low cost, may provide



the necessary overcapacity and insurance against unscheduled breakdown. Thus, if the scraper mining scheme operates according to design, nearly all the equipment will be in use all the time. Another point of comparison has to do with the time value of capital. With large custom units it is necessary to commit funds for purchase considerably in advance of plant startup. But the cost of scrapers may be spread over the entire life of the project.

## PROCESSING OF MINED TAR SANDS FOR BITUMEN RECOVERY

### Direct Coking of Tar Sands

Direct coking of tar sands, using a fluidized-bed technique, has been tested by the Canadian Department of Mines and Technical Surveys, Mines Branch [22]. Figure 31 is a simplified flow sheet of the pilot plant. Tar sand is fed to a first vessel which is a coker or still, operating at about 900°F. In the coker, the tar sand is heated by contact with a fluidized bed of clean sand from which the coke has been removed by burning. Volatile portions of the bitumen are distilled from the sand grains. Residual portions are thermally cracked, depositing a layer of coke around each sand grain. Coked solids are withdrawn from the coker down a standpipe, fluidized with air, and transferred to a second vessel. This vessel is a burner or regenerator; it operates at about 1400°F. In the regenerator most of the coke is burned off the sand grains. The clean hot sand is withdrawn through a standpipe. Part (20-40%) is rejected, and the balance of the clean hot sand is recirculated to the coker to provide the heat for the coking reaction. Products leave the coker as a vapor, which is condensed in a product receiver. Reaction offgases from the receiver are recirculated to fluidize the clean, hot sand which is returned to the coker. Condensate from the product receiver forms a heavy synthetic crude oil, the principal reaction product. Typical properties of the synthetic crude are summarized in Table 6 (see page 25). Operating data from a number of coking runs on tar sands at different temperatures are summarized in Table 8. The main point to note is that to raise the coker temperature, it is necessary to raise the temperature in the burner, and/or increase the recirculation rate (recycle ratio) of hot sand to the coker. At the highest recycle ratio of 5.0, the weight ratio of sand to oil in the coker is about 35. For comparison, typical catalyst/oil weight ratios in fluidized bed catalytic cracking range from 8 to 10.

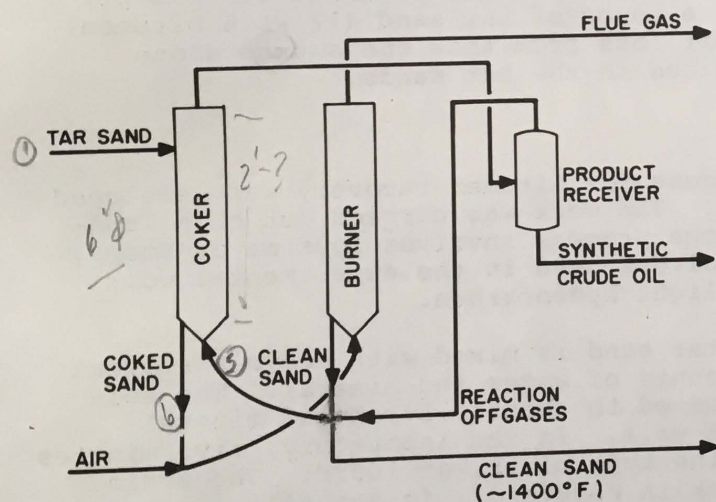


Fig. 31 Direct Fluid Coking of Tar Sands, Source [22]

A fluidized solids technique for direct coking of tar sands is attractive for several reasons. The process is a simple, direct treatment of the tar sand. Furthermore, the technology involved is similar to that in fluid catalytic cracking, so that it is reasonable to expect that large units could be engineered and scaled-up reliably. A significant advantage, relative to the hot water process (discussed below), is that feeds of

*9 lbs clean sand to coker = 5  
2 lbs tar sand to coker  
at 20 tons tar feed  
this would equal  
100 T/H recycle*

*→ 20  
→ 2  
1690 + 20 = 3.2*

*120  
120 : 37.5  
3.2 =*



OFF GASES

CLEAN SAND  
(~1400°F)

Direct Fluid Coking of Tar Sands,  
Source [22]

nology involved  
fluid catalytic  
is reasonable to  
units could be e  
up reliably. A  
relative to the  
(discussed below

$$\frac{9 \text{ bs clean sand to coke}}{9 \text{ bs tar sand to coke}} = 5$$

At 20% tar feed  
this would equal  
1.00 T/H recycle

→ 20  
→ 2

$1690 + 20 = 3.2$



TABLE 8  
DIRECT COKING OF ATHABASCA TAR SAND  
PILOT PLANT OPERATING DATA

Feed	Abasand Run No.				Source of Tar Sand			
	(1)	(2)	(3)	(4)	(1)	(2)	(3)	(4)
Composition, wt. %								
bitumen	17.0	16.4	16.4	16.4	13.5	13.5	14.5	15.8
water	0.3	0.3	0.5	0.3	0.35	0.5	nil	0.9
Rate								
lb/hr.	83	86.4	75.5	83	107	88.6	85.4	79
lb/hr. sq. ft.	434	450	394	434	560	463	445	412
lb/hr. cu. ft. bed volume	169	176	154	169	219	180	173	161
Operating Conditions								
coker Temperature, °F	925	977	1022	1067	932	950	977	1022
burner Temperature, °F	1303	1286	1373	1436	1220	1320	1265	1400
recycle ratio <u>lb clean sand to Coker</u>								
lb tar sand to Coker	2.9	4.4	3.8	5.0	4.4	4.7	--	3.9
Oil Product								
Yield, Vol. %	84.0	83.5	75.0	73.5	85.7	86.5	86.0	82.5
Data: Reference 22								

high fines content offer no particular difficulty. There are two possibly serious disadvantages to direct coking. First, large amounts of sand must be circulated relative to the oil throughput. Under reaction conditions, the sand may prove to be abrasive, causing material handling problems. The second point is that the sand discharged from the process is hot (1400°F) and thus represents a significant heat loss. No practical way has yet been suggested for recovering the large amount of sensible heat in the reject sand from a direct coking process. To heat the sand to 1400°F requires about 240 BTU per pound of tar sand. The heating value of a pound of tar sand (12 wt.% bitumen) is about 2100 BTU. Thus, the process heat loss from this one source alone represents over 10 wt.% of bitumen contained in the tar sands.

#### Anhydrous Solvent Extraction Process

An anhydrous solvent extraction process for bitumen recovery was developed by Cities Service Athabasca Limited [13]. The work was carried out on a laboratory scale during 1959-61. The anhydrous process involves four major steps, shown schematically in Figure 32. The solvent used in the experimental work was not specified; presumably, it was a light hydrocarbon.

In the first or mixer stage, fresh tar sand is mixed with recycle solvent which contains some bitumen and minor amounts of water and mineral. The solvent to bitumen ratio (by volume) is adjusted to about 0.5. Total mineral content of the mixer effluent is about 55 wt.%. In the laboratory, five minutes was sufficient mixing time, using a turbine type mixer, at 100°F. The drain step, which is summarized by a single block in Figure 32, is actually the heart of the solvent extraction process. This step consists of a three stage counter-current wash. Settling and draining time is about 30 minutes for each stage. The Cities Service extraction process does not use conventional mixer-settler type equipment. Instead, after each extraction step, a bed of sand is formed



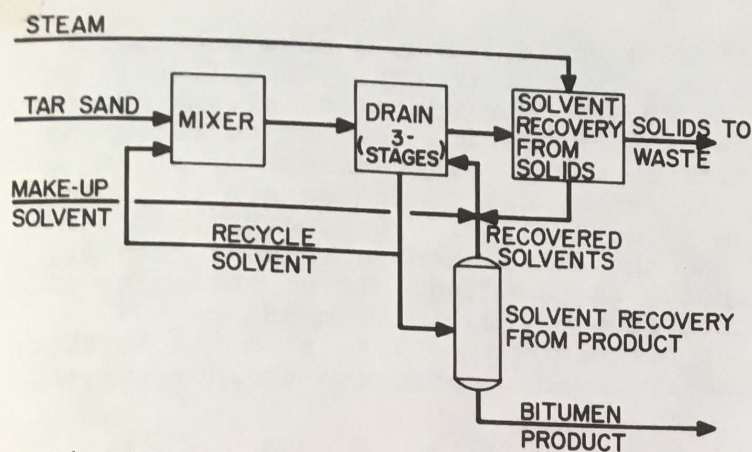


Fig. 32 Anhydrous Bitumen Recovery Process, Source [13]

and the extract is drained through this bed, until the interstitial pore volume of the bed is emptied. The reason for this variation, presumably, is to minimize losses of solvent physically entrained with the sand. In typical runs, drain rates were on the order of 10 gal/min sq. ft., and were dependent on extract viscosity, sand bed depth, and applied pressure differential. Maximum pressure differential was 15" Hg. It was observed that the bed blinded irregularly, causing the drainage rate to be essentially zero which, in turn, caused that extraction stage in which the blinding condition occurred to be totally ineffective.

The last two steps of the process are devoted to solvent recovery. Stripping of the solvent from the bitumen is straightforward. The step of solvent recovery from the solids holds the key to the economic success of an anhydrous process. A calculated material balance for the anhydrous process is summarized in Table 9. If all steps operate according to theory, 93% of the feed bitumen is recovered. Solvent loss is only 1% of circulation, but nearly 3.2 lb. solvent are circulated for each lb. of bitumen recovered. This solvent loss must eventually be made up from the bitumen product, probably by some process such

TABLE 9  
CALCULATED MATERIAL BALANCE IN  
ANHYDROUS BITUMEN RECOVERY PROCESS (13)<sup>a</sup>

Stream	Component, lb				
	Bitumen	Solvent	Mineral	Water	Total
Mixer step					
tar sand	380.0		2639.4	234.3	3254.5
recycle solvent	761.5	860.5	29.3	18.3	1669.6
Drain step					
makeup solvent		10.3			10.3
solvent recovered					
from product		266.7			266.7
from sand	11.4	192.3			204.5
feed from mixer	1142.3	860.5	2660.1	250.7	4924.1
product	1115.6	1127.2	41.8	26.2	2310.2
solids-to-solvent					
recovery	38.1	202.6	2627.0	227.1	3094.8
Solvent recovery step					
from product					
feed to stripper	354.1	266.7	12.5	7.9	641.3
bitumen product	354.1		12.5	7.9	374.5
from solids					
steam				149.1	149.1
solids to waste	26.7	10.3	2626.9	375.5	3039.4
<hr/>					
Recoveries and losses	With solvent recovery from solids		Without solvent recovery from solids		
Solvent loss, % of circulation	1.0		18.0		
Bitumen recovery, % of feed bitumen	93.0		90.0		
Bitumen recovery, equivalent to 100% solvent recovery, %	89.3		19.0		

<sup>a</sup> Calculated on the basis of 1 bbl bitumen recovered.



as coking which will have less than 100 vol.% yield. Thus a more meaningful recovery figure is that equivalent to 100% solvent recovery. This figure, assuming solvent stripping from the solids, is 89.3%. The amount of steam indicated in the material balance (Table 9) is just the theoretical amount to raise the temperature of the tar sand feed from 32°F to 212°F. This amount of steam is a fair estimate of the process heat requirements, but is inadequate to accomplish much stripping of solvent from the reject solids. It appears from comparing the solvent recovered from sand and the solids fed to solvent recovery (Table 9) that an excellent job of stripping is expected. If no stripping of the reject solids is accomplished, bitumen recovery falls from 93% to 90%. Solvent losses increase from 1% to 18% of circulation. This is an intolerably large loss since the corresponding bitumen recovery, corrected to 100% solvent recovery, is only 19%.

### Cold Water Separation Processes

Two cold water bitumen separation processes have been developed to the point of small scale continuous pilot plants. One process [33], developed by the Mines Branch of the Canadian Department of Mines & Technical Surveys in 1949-50, uses a combination of cold water and solvent. A second process, called sand reduction, was developed by Imperial Oil Enterprises Limited [34]. This process uses cold water only, with no solvent. The Mines Branch project was an outgrowth of the work at the Abasand pilot plant which originally employed a hot water process. When the Dominion Government took over Abasand Oils Ltd. after the company's financial failure, it was apparently suggested that heat economies could be achieved by cold water processing. Thus the 500 ton per day pilot plant (which was never operated) was to have used the cold water process.

The Mines Branch cold water separation process is shown schematically in Figure 33. The process, which employs four steps, was demonstrated in a 200 lb. per hour continuous pilot plant. The first process step is called disintegration and is carried out in a pebble mill. This step accomplishes disintegration of the charge, and its mixing with water, diluent and reagents. The mill contains 1/2 lb. of pebbles for each one lb/hr of tar sand feed capacity. Kerosene is the diluent and is added to the bitumen in the feed at a weight ratio of about one to one. Part of the process water is also added in the disintegration stage. Total water addition for the process is 2 to 3 times the weight of the tar sand. Addition of reagents is critical to the cold water process. The pH is controlled within a range of 9 to 9.5 by the addition of approximately 1.5 lbs. of soda ash per ton of tar sand. In addition to the soda ash, wetting agents are also added. Those tested were Span 40, Span 80 and Resin Amine Diacetate, each added at the rate of 0.04 lb. per ton of tar sand.

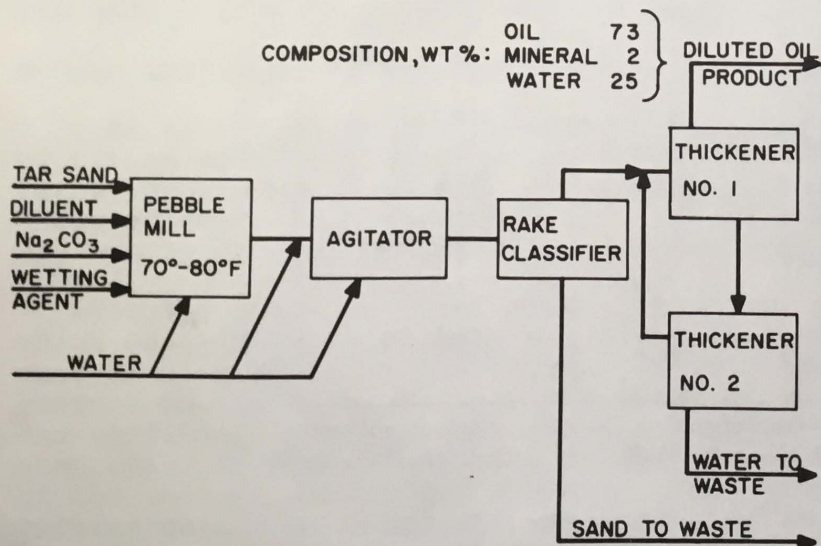


Fig. 33 Cold Water Bitumen Recovery Process, Source [33]

The second step in the cold water process is an agitator. In this vessel the pebble mill effluent is mixed with additional water,



and a shearing action occurs by which the bitumen is separated from the sand grains. The third process step is a raked classifier. In this step the sand is settled from the bulk of the remaining mixture. The water and oil overflow the classifier and go to the fourth process step, thickeners, which concentrate the oil.

The classifier overflow is fed to thickener #1, the overflow of which constitutes the oil product of the process. The underflow from the first thickener is made up primarily of water and fine solids, with some entrained oil. This oil is recovered as the overflow of thickener #2 and recycled to the process. The underflow from thickener #2 is a waste water stream. It was noted during experimental work that clay in the tar sand feed has a distinct effect on the process, in that it forms hard-to-break emulsions which are wasted with the underflow from thickener #2 and detract from process recovery. The experimental work on the Mines Branch cold water process was carried out with Abasand tar sand which constitutes a feed of low fines content (see Figure 16, page 21). Oil product from the cold water separation process has a nominal composition by weight: oil (bitumen diluted 1/1 with kerosene) 73%, mineral 2%, and water 25%.

The sand reduction process is shown schematically in Figure 34. This process consists of three major steps, which are roughly analogous to the four steps of the Mines Branch cold water process. In the first step the tar sand feed is mixed with water at about 70°F in a screw conveyor. Water is added in the ratio of 0.75-3 tons/ton tar sand, with the lower range being preferred. The mixed pulp from the screw conveyor is discharged into a rotary drum screen, which is submerged in a water-filled settling vessel. The bitumen forms agglomerates which are retained by the twenty mesh screen and sink through the settling vessel. These are withdrawn as the oil product. The sand readily passes the twenty mesh screen and is withdrawn from the bottom of the settling vessel as a waste stream. The process is called sand reduction because its objective is the removal of sand from the tar sand, to provide a feed suitable for a fluid coking process. Approximately 80% removal of sand is claimed. The second step (submerged screening) accomplishes the same functions as the agitator and raked classifier in the Mines Branch process. A third stream, mainly water and suspended mineral, is taken from the submerged screen settling vessel. This stream is sent to a clarifier. Oil is skimmed from the surface and water is returned to the process. Nominal composition of the oil product (by weight) is: oil (bitumen) 58%, mineral 27%, and water 15%. The sand reduction process is said to be tolerant of fines (defined as minus 200 mesh mineral matter) up to about 25 wt.% of the total tar sand mineral.

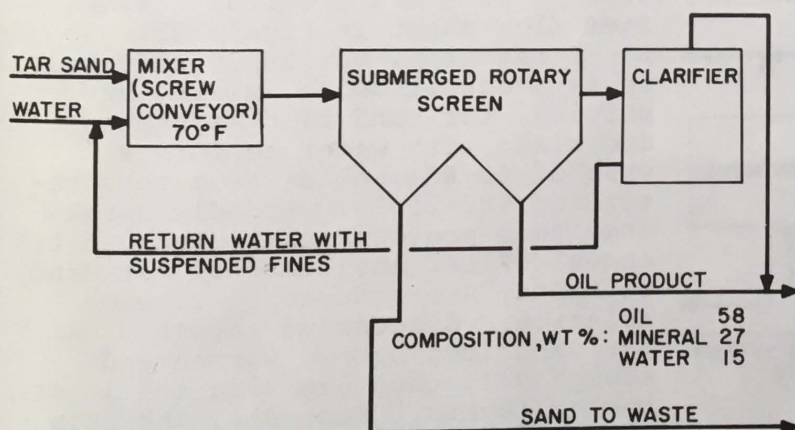


Fig. 34 Sand Reduction Process, Source [34]

A process called spherical agglomeration has been described [53] by Puddington et al, at the National Research Council in Ottawa. The process, which has been briefly applied to tar sands [54], is remarkably like the sand reduction process. Stated generally, spherical agglomeration is a combination chemical-mechanical treatment for recovery of finely divided and suspended solids. A bridging liquid, which is insoluble in the suspending medium and which wets the solid surface, is added to the suspension



with agitation. The agitation causes repeated collisions among solid particles. The bridging liquid forms surface tension bonds among the solid particles which eventually agglomerate into dense spheres. Surfactants may be needed to condition the solid surface so it will be wetted by the bridging liquid.

In applying this theory to oil sands, Puddington et al have regarded bitumen as the suspending medium and sand as the dispersed solids. Water was added as the bridging liquid and the mixture was ball milled [54]. The surprising result was that the sand became water wet but did not agglomerate. The bitumen formed dense agglomerates of 75-87 wt.% bitumen, 12-25 wt.% sand and 1-5 wt.% water.

The major difference between the Mines Branch and the sand reduction (or spherical agglomeration) processes is in the mineral and water content of the oil product. The sand reduction process has, as its objective, the production of a feed of low heat capacity per unit of bitumen content, a feed which would be suitable for a fluidized coking process. The heat requirements of such a process would be minimized by reducing both the sand-to-oil and water-to-oil ratios. The feed to a fluidized coking process could, of course, tolerate a relatively large mineral content. In contrast, the cold water process tends to reduce both water and mineral contents, but particularly mineral content, with a view to some alternate form of bitumen upgrading.

### Hot Water Process

The hot water bitumen extraction process is, and probably will remain closely linked with the name of Dr. K. A. Clark who first described the process in 1923 [35]. From that start he devoted himself to research on the hot water extraction process more or less continuously through the pilot plant program at Bitumount in 1948-49. Since that time, two major industrially sponsored pilot plant efforts have been devoted to the hot water process. The first of these was led by Cities Service Athabasca, Inc. in association with Imperial Oil, Limited, Richfield Oil Corp., and Royalite Oil Company, Ltd. (now the Syncrude group). This program was carried out during 1959-62 at Mildred Lake near the present GCOS plant site and later in Edmonton. The second effort was by GCOS, during 1963-1965, at the plant site.

Despite some differences in detail, the hot water processes described respectively by Clark [36], Cities Service [20], and GCOS [14], have a great deal in common. The essentials of the hot water process are shown as a simplified flow sheet in Figure 35. In

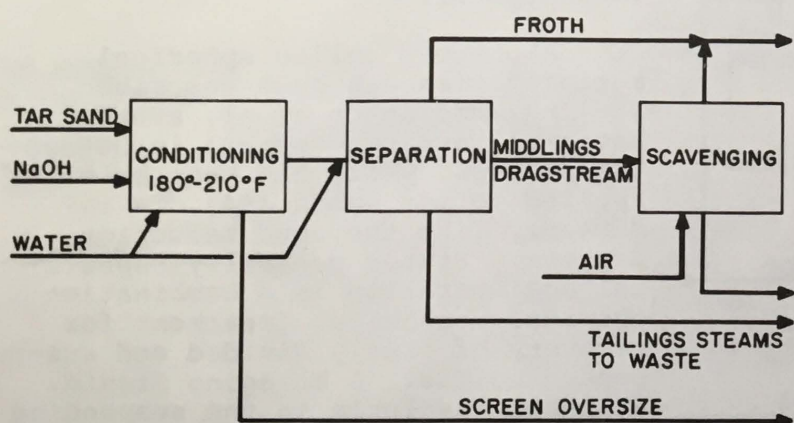


Fig. 35 Hot Water Bitumen Recovery Process

the first step, variously referred to as a conditioning, mixing or pulping, tar sand feed is heated and mixed with water to form a pulp of 60-85% solids at a temperature of 180-200°F. Broadly speaking, this process takes place in two steps. First the lumps of tar sand, as mined, are reduced in size by ablation. Successive layers of each tar sand lump become warmed and slough off, thus exposing the inner, cooler layers. Secondly, the pulp so formed is mechanically mixed, reacted with any chemicals added,



and further heated to the process temperature. Conditioning can be accomplished by open steam heating in a horizontal rotating drum. A great deal of research has been done on the effect of high shear mixing [37], water content of the pulp, and reaction of the caustic soda or other conditioning reagents with the tar sands [38, 17]. It has been shown, however, that all of these reactions are relatively rapid compared to the step of feed lump size reduction by abrasion [14]. Thus, from the point of view of equipment scaleup, conditioning can be regarded essentially as a heat transfer process. The effluent from the conditioning drum is screened to remove tramp material or tar sand lumps which were not sufficiently reduced in size. The screened pulp is mixed with any added water, adjusted to the proper consistency for pumping, as described below, and sent to the separation cell.

The separation cell acts as two settlers, one above the other; the lower settles sand down and the upper settles bitumen up (i.e. floats the bitumen). The bulk of the sand in the feed is removed from the bottom of the separation cell as tailings. A major portion of the feed bitumen floats to the surface of the separation cell and is removed as froth. A middlings stream consisting mostly of water, but with some suspended fine mineral and bitumen particles, is the third stream removed from the separation cell. A portion of the middlings may be returned for mixing with the conditioning drum effluent in order to properly dilute the separation cell feed for pumping. The balance of the middlings is called the drag stream. The drag stream is withdrawn from the separation cell to be rejected after processing in the scavenger cells. Tar sand feed contains a certain portion of fine mineral. This material, if allowed to build up in concentration in the middlings, increases the viscosity and eventually will cause all settling to cease in the separation cell. It is in order to control the fines concentration in the middlings that the drag stream is required as a purge. The amounts of water that come in with the feed and leave with the separation cell tailings and froth are relatively fixed. Thus, the size of the drag stream directly determines the makeup water requirement for the separation cell. The separation cell is simply an open, straight-sided vessel with a cone bottom. Mechanical rakes on the bottom move the sand toward the center for discharge. Wiper arms rotating on the surface push the froth to the outside of the separation cell. The froth then overflows into launders for collection.

The third step in the hot water process is scavenging. Depending on the drag stream size and composition, enough bitumen may leave the process in the drag stream to make another recovery step economic. Scavenging may be accomplished by froth flotation using air. The scavenger froth is combined with the separation cell froth, to be further treated and upgraded to synthetic crude oil. Tailings from the scavenger cell join the separation cell tailings stream and go to waste. Conventional froth flotation cells are suitable for the scavenging step.

The three major process steps may also be explained in terms of the separation mechanism, as viewed on the microscale. Figure 7 (see page 13) depicts sand grains as being surrounded by a water film and a bitumen film. The conditioning process provides enough shearing agitation to rupture these bitumen films and cause the bitumen to disassociate from the sand grains as suspended flecks of oil. In a sense, then, as the pulp leaves the conditioning drum the separation of bitumen from sand has actually been accomplished; the remainder of the process is simply for the purpose of collecting the separated materials. In the separation cell, the bitumen particles rise to the surface of the middlings and agglomerate together to form a coherent mass, which is collected as a froth floating on the surface of the middlings. On an air free



basis, bitumen froth has a density roughly equal to, or slightly greater than, the middlings on which it floats. It is by inclusion of upwards of 30 vol.% of gas bubbles that the bitumen flecks readily float to form froth. Since the process is carried out at about 180°F, much of the gas is water vapor. The balance is air which has been entrained during conditioning and pumping to the separation cell. No air is added to the separation cell.

Based on laboratory studies, and the Bitumount pilot plant work, Clark described a step (called flooding) between the conditioning and separation steps. The purpose of the flooding step was to achieve high shear mixing without air entrainment. Considerable importance was attached to this step, particularly to the exclusion of air. Air entrainment was said to lead to increased mineral content in the froth. From the GCOS pilot plant work it was concluded that no special provisions for flooding need be made; the diluted pulp can be transferred to the separation cell by centrifugal pumps. In the scavenging step, an attempt is made to recover bitumen particles which do not float in the separation cell. These particles evidently are finer, or less air-avid than are the bitumen particles collected in the separation cell. Therefore, air must be added in the scavenging cell to accomplish recovery of these more refractory bitumen particles.

Despite the large amount of recent pilot plant work which has been described in the literature, no material balance around the separation cell has been given. However, from the data of Fear and Innes [14], a reasonable material balance may be pieced together. The triangle diagram in Figure 36 is a convenient way of representing the calculations required. Assume a feed of 13% bitumen and 13% fines corresponding to Fear and Innes' Figure 15 (F-I 15). This is represented in Figure 36 by point A. Corresponding to 13% feed fines, a reasonable water addition rate (F-I 16) is 0.5 tons/ton tar sand. Water is represented by Point B in Figure 36. Using the lever arm mixing rule for triangle charts, the total mix of feed and water is located at point C. Allowing for a small amount of screen oversize (assumed to have the same composition as the tar sand feed), the mixture to be processed after removal of the oversize is located at point C' nearly identical with point C. Bitumen distribution among the three streams leaving the separation cell is given by (F-I 11) and (F-I 15). Typical separation cell froth composition is located at point D. Again using the lever arm rule, point E represents the sum of the middlings and tailings

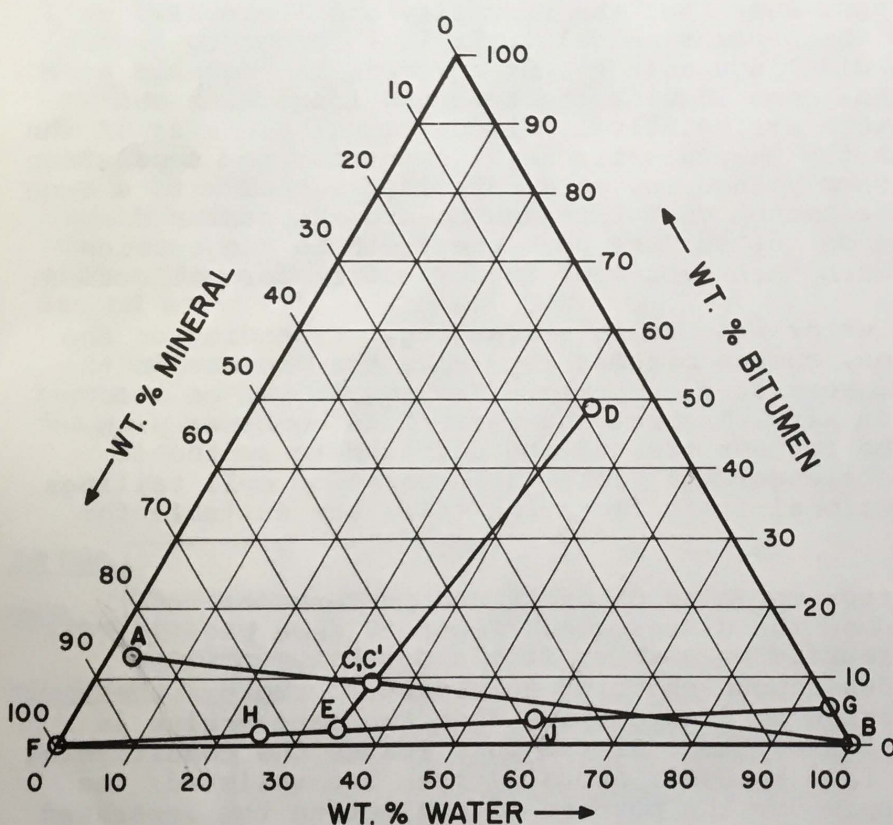


Fig. 36 Triangle Diagram Construction of Material Balance for Hot Water Separation

the calculations required. Assume a feed of 13% bitumen and 13% fines corresponding to Fear and Innes' Figure 15 (F-I 15). This is represented in Figure 36 by point A. Corresponding to 13% feed fines, a reasonable water addition rate (F-I 16) is 0.5 tons/ton tar sand. Water is represented by Point B in Figure 36. Using the lever arm mixing rule for triangle charts, the total mix of feed and water is located at point C. Allowing for a small amount of screen oversize (assumed to have the same composition as the tar sand feed), the mixture to be processed after removal of the oversize is located at point C' nearly identical with point C. Bitumen distribution among the three streams leaving the separation cell is given by (F-I 11) and (F-I 15). Typical separation cell froth composition is located at point D. Again using the lever arm rule, point E represents the sum of the middlings and tailings



streams. Referring to (F-I 12) the bitumen to water ratio is approximately the same in the middlings and tailings streams on the triangle chart. This means that both the middlings and the tailings compositions lie on the line through point E and the vertex F (100% mineral). Extending the line EF gives the point G indicating a bitumen to water ratio of about 0.05 in middlings and tailings. The typical solids content of separation cell tailings is 75%. This allows point H to be located along the line FEG. The weight of the tailings stream can now be calculated using the bitumen distribution, bitumen/water ratio, and tailings composition. By once more using the lever arm rule, the middlings composition can be located at point J. The result of the calculation is summarized in Table 10.

The thermodynamics of the hot water separation process have been formulated elegantly [17]. The system employs extremely complicated surface chemistry involving interfaces among various combinations of solids (including both silica sand and aluminosilicate clays), water, bitumen (which contains polar sulfur- and nitrogen-containing molecules) and air. While the mathematical framework for expressing the various relationships has been provided, data are lacking. Apparently critical to the process is the control of pH, the preferred range being 8.0 to 8.5. This range can be achieved with any of the monovalent bases. Polyvalent cations must be excluded from the process because they tend to flocculate the clays, thus raising the middlings viscosity in the separation cell. The relationships among clay concentration, flocculating ion concentration and middlings viscosity have been described [39].

A process described as "hot water extraction" has been applied on a laboratory scale by the U.S. Bureau of Mines to U.S. tar sand [10]. This process is distinctly different from hot water separation as described above because a solvent is used. In the USBM hot water process, a 33° API fuel oil containing 20-25 vol.% aromatics is added as solvent in a 1:3 weight ratio based on the feed bitumen content. Solvent is added in the conditioning stage. The product of this process closely resembles that of the Canadian Mines Branch cold water process. The composition of froth recovered from Edna, California tar sands was 73%, 6%, and 21% by weight, respectively of diluted bitumen, mineral, and water.

Despite the complication of using a high-boiling solvent, the same fundamental mechanisms seem to apply to the USBM process. Tar sand from the Vernal deposit in Utah (8.7-13.9% bitumen, 2% fines) was processed with a bitumen recovery of 96%. Tar sand from the Sunnyside deposit in Utah actually

TABLE 10  
CALCULATED MATERIAL BALANCE FOR  
HOT WATER BITUMEN EXTRACTION PROCESS (14)<sup>a</sup>

Component	Process inputs, lbs		Process outputs, lbs			
	Tar sand	Water	Screen oversize	Froth	Tailings	Middlings dragstream
Bitumen	260		2.6	211.2	23.1	23.1
Mineral	1660		16.6	38.8	1360.0	244.6
Water	80	1000	0.8	181.0	456.9	441.3
total	2000	1000	20.0	431.0	1840.0	709.0

<sup>a</sup> Calculated on the basis of 1 ton tar sand processed.



occurs as an extremely hard asphaltic rock that must be crushed to small size to facilitate complete disintegration and displacement of the bitumen from the sand grains. In the crushing operation, large quantities of silt are produced (fines content is 9-17%). This increased the water requirement relative to the Vernal tar sand and decreased the recovery to 90%. The tar sand deposit at Edna, California (11% bitumen, 6% fines) is unusual in that it contains, in the connate water, large concentrations of iron and calcium salts. With these present, bitumen cannot be extracted by the hot water process; however, if the tar sand is washed with hot water before conditioning to remove the polyvalent cations, then the hot water process can be successfully applied. The effect of the polyvalent cations is to form, under the basic processing conditions, gelatinous slimes. These prevent proper froth flotation and reduce recovery to 50% or less.

## UPGRADING THE VALUE OF BITUMEN

There are two objectives in product upgrading, the first of which is the conversion of froth (from those processes which yield froth as a product) to the hydrocarbon bitumen. The second objective is upgrading of the bitumen itself to a more saleable product which can be generally described as a synthetic crude oil. Refining of synthetic crude to useful consumer goods such as gasoline and home heating oil can then be accomplished by conventional means.

### Froth Cleanup Processes

Three types of froth cleanup processes have been described in the literature, but no detailed data have been published. Froth from the hot water process may be mixed with a hydrocarbon diluent (such as coker naphtha) for viscosity reduction and then centrifuged. The GCOS process [23] is a two-stage centrifuging operation, each stage consisting of multiple centrifuges of conventional design installed in parallel. Bitumen product contains 1-2 wt.% mineral, (dry bitumen basis) and 5-15 wt.% water (wet diluted basis). Cities Service Athabasca proposed a two-stage froth cleanup process. The first stage accomplishes the bulk of the mineral removal by water washing; the second stage is thermal dehydration. A third process, proposed by Shell, is electrical dehydration. This process was also proposed by GCOS in their original application to the Oil and Gas Conservation Board (1960-1962). It is analagous to electrostatic methods of desalting conventional crude oil.

A partial coking or thermal deasphalting process has been proposed [40] to provide minimal upgrading of bitumen. The objective of the process is to remove mineral and water from a hot water process froth, yielding a dehydrated and mineral free bitumen product which still contains most of the asphaltenes and Ramsbottom carbon content. Partial coking consists simply of distilling hot water process froth at atmospheric pressure. The process has been carried out batchwise in laboratory tests over a period of from 30 minutes to 4 hours. Thermal cracking begins as the liquid temperature passes 650°F. The distillation is continued to 700-850°F. When the heating is done slowly (50°F liquid temperature rise per hour) coke production rate is approximately 1 wt.% of feed per hour. The coke forms around the entrained mineral particles as nuclei. In the process of forming 1-4 wt.% coke, up to 50 vol.% of the feed is recovered as distillate. After this treatment, the residue may be filtered to yield an essentially ash free product. The ash free residue is then suitable for several applications, such as metallurgical coke and production of bituminous paints, for which the original mineral content would have disqualified it.



## Refining of Bitumen: Conversion

The commercially proposed tar sand ventures have in common the objective to market an upgraded (and hence relatively more valuable) product, and a sizeable need for fuel at the bitumen recovery site. To meet these two needs, a two step refining sequence is used (or proposed). The main purpose of the first step is conversion of the (~50%) nondistillable residue to distillate (nominally 1000°F<sup>-</sup>) hydrocarbon. The second step is hydrotreating of the distillate to economic values of boiling range and sulfur, nitrogen, and hydrogen content.

The onsite fuel requirement for bitumen recovery from tar sand amounts to 15-30% of the bitumen recovered (in conventional refining the fuel requirement is 10-15% of crude run). From heat balance considerations only then, conversion of 40% to 70% of the 1000°F<sup>+</sup> residue of bitumen leaves sufficient fuel in the unconverted residuum to operate the process; however, this residuum contains sulfur, finely divided mineral, and organometallic vanadium and nickel, all in concentrations undesirable from the points of view of boiler operation and of ecological concerns. Thus, not only the heat balance but other important economic and social considerations govern the actual choice of conversion level and fuel.

Conversion processes which have been proposed for Athabasca bitumen are summarized in Table 11, and are described in more detail below.

### Coking

Coking can be carried out in a number of ways, including direct coking of tar sands (as described above), fluid coking, delayed coking, and destructive batch distillation of bitumen. In each case the charge is converted to distillate oil and coke. The coke fraction of the product satisfies the need for fuel. The coker distillate is a partially upgraded material in itself, and is a suitable feed for hydrodesulfurization to produce a sweet synthetic crude. Coking followed by hydrodesulfurization, which is the process route recommended in the Blair report [5], is the process used commercially by GCOS.

Operating conditions and product yields for the direct coking of tar sands have been described above. Inspections of the whole coker distillate are given in Table 6 (see page 25). Properties of distillate fractions are detailed in Tables 12 and 13. As noted earlier, the chemical composition of bitumen in the Athabasca deposit is nearly the same over rather wide geographical areas. Thus, it is not surprising that the distillates made from Abasand tar sands (Table 12) and Bitumount tar sands (Table 13) are quite similar. Sulfur is well distributed throughout the boiling range in both distillates. The aromatics content of both distillate samples, however, is low compared to delayed coker distillates. In fact, none of the Abasand fractions boiling below 750°F had over 20% aromatics. This result is a bit surprising since the parent bitumen contained over 50% asphaltenes and resins.

As the temperature of coking is decreased in the range 1000° to 800°F and the residence time correspondingly increased, operating conditions shift from fluid coking and approach once-through or delayed coking. In delayed coking the charge oil is heated to a temperature of normally between 900° and 950°F to initiate the coking reactions. The heated oil is then fed to large drums where all the material which will vaporize is allowed to do so. The residue is left behind to polymerize to coke. The various coking operations



TABLE 11  
CONVERSION PROCESSES FOR BITUMEN

	Coking		Visbreaking	Hydrovisbreaking	
	Delayed	Fluid Coking		Thermal	Catalytic
Conversion, wt % > 990°F	50 - 54	64 - 78	24 - 46	33 - 75	39 - 85
Yield, wt % Feed					
C <sub>4</sub> - Gas	6.7 - 8.3	8.9 - 11.6	1 - 4		
C <sub>5</sub> + Distillate	67.7 - 70.4	75.4 - 81.1	57 - 66		up to 93.6
990°F+ Resid		0 - 9.3	30 - 42	11 - 31 <sup>1/</sup>	7.5 - 28
Coke	21.0 - 23.2	7.3 - 10			
Reference	[23, 24, 41, 64]	[64]	[64]	[62, 63]	[62, 64]

<sup>1/</sup> Volume percent

produce different coke yields, with lower coking temperatures and longer residence times (as in delayed vs. fluidized coking) favoring higher coke yields. Figure 37 summarizes the range of values which have been obtained in coke and distillate yields.

Both pilot plant and commercial yield data are available on delayed coking of Athabasca bitumen and are summarized in Table 14. Table 15 summarizes inspections on fractions of delayed coker distillate. Corresponding inspections on the whole synthetic crudes from which these fractions are taken are summarized in Table 6 (page 25). Sulfur is distributed throughout the boiling range of the delayed coker distillate as it is with the direct coker distillate. Nitrogen, which averaged 5000 ppm in the bitumen feed, is more heavily concentrated in the higher boiling fractions; nevertheless, it is present in all

TABLE 12  
INSPECTIONS OF COKER DISTILLATE<sup>a</sup> FRACTIONS (22)

Inspection	Composite	Distillation range, °F						Residue
		ibp to 356	356 to 464	464 to 536	536 to 608	608 to 644	644 to 750	
Specific gravity, 60°/60°F	0.960	0.7720	0.8497	0.8801	0.9009	0.9165	0.9439	1.019
Refractive index		1.4348	1.4719	1.4860	1.4980	1.5061	1.5234	
Sulfur, wt. %	4.01	1.70	2.59	2.69	3.21	2.76	3.51	4.92
Viscosity, cSt								
at 100°F	43.2	1.24	1.65	2.73	3.98	8.51	27.7	10,721.0
at 210°F	5.7	0.77	0.8	1.12	1.58	2.12	3.9	77.8
Percent of coker distillate								
by vol		6.6	5.9	3.6	5.8	3.4	17.8	54.7
by wt		5.1	5.0	3.2	5.7	3.1	16.8	55.7
Asphaltenes, wt. %	1.2	nil	nil	nil	nil	trace	trace	3.75
Resins, wt. %	18.7	0.94	1.8	2.4	3.0	4.1	4.4	39.4
Oily material, wt. %	77.8	99	98.2	97.6	97.0	95.2	93.9	57.9
Aromatics, wt. %		7.4	16.1	17.3	12.8	19.7	17.4	
Acid soluble, wt. %		63.3	51.2	45.5	48.8	45.7	54.6	
Acid insoluble, wt. %		29.3	32.7	37.2	38.4	34.6	27.8	

<sup>a</sup> Produced by direct fluidized solids coking of Abasand tar sands (977°F).



TABLE 13  
INSPECTIONS OF COKER DISTILLATE<sup>a</sup> FRACTIONS (22)

Inspection	Composite	Distillation range, °F						Residue
		ibp to 356	356 to 464	464 to 536	536 to 608	608 to 644	644 to 750	
Specific gravity, 60°/60°F	0.954	0.7875	0.8477	0.8747	0.9000	0.9218	0.9465	1.003
Refractive index		1.4384	1.4680	1.4815	1.4952	1.5098	1.5252	
Sulfur, wt. %	4.0	1.71	1.87	2.12	2.70	3.03	3.61	4.74
Viscosity, cSt								
at 100°F	52.0	2.1	1.88	2.91	5.14	9.81	28.7	4550.0
at 210°F	5.2	1.06	0.87	1.15	1.59	2.27	4.0	54.0
Percent of coker distillate								
by vol		3.5	6.1	5.7	7.7	4.0	17.2	50.0
by wt		2.8	5.2	5.0	6.9	3.7	16.2	50.2
Asphaltenes, wt. %	0.5	nil	nil	nil	nil	trace	trace	1.03
Resins, wt. %	22.6	1.40	1.66	1.74	2.2	3.9	6.7	26.6
Oily material, wt. %	72.5	98.0	98.0	97.6	97.0	94.5	92.7	71.7
Aromatics, wt. %		4.9	11.4	12.4	18.4	33.3	38.4	
Acid soluble, wt. %		44.8	41.3	39.0	39.6	29.5	38.6	
Acid insoluble, wt. %		50.3	47.3	48.6	42.1	37.1	25.0	

<sup>a</sup> Produced by direct fluidized solids coking of Bitumount tar sands (944°F).

distillate fractions. Note that the gas oil has the high aromatics content typical of coker gas oils.

Figure 38 gives a generalized correlation for the coke sulfur content

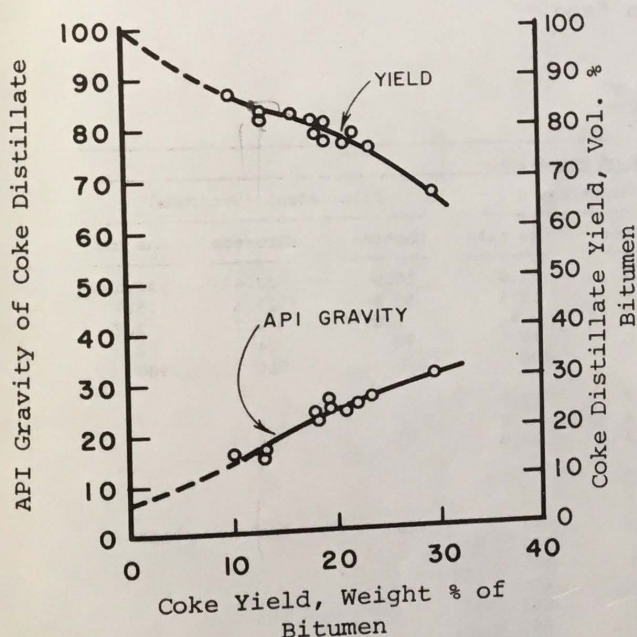


Fig. 37 Yields & Gravities of Various Coke Distillates Produced from Bitumen, Source [24]

from a number of possible feeds. These data are compatible with the data on distillate fractions, and again show that coking does not produce significant concentration of sulfur in any one fraction. These data also emphasize that, with a high sulfur feed such as bitumen, a high sulfur coke will be produced. Table 16 summarizes a sulfur balance over a pilot plant delayed coking run.

Fluid coking is a proprietary process offered for license by Esso Research and Engineering Company. Figure 39 is a schematic flowsheet of the process. Briefly, bitumen feed is heated in the reactor vessel by direct contact with a fluidized bed of hot coke. Vapor product is taken overhead. Cold coke is partially burned in the burner vessel, from which the net coke product is ultimately withdrawn. Tables 17 and 18 summarize yield and inspection data from pilot plant coking of bitumen.



TABLE 14

## PRODUCT YIELD FROM THE DELAYED COKING OF BITUMEN

Product	Scale of Operation			
	Pilot plant	Pilot plant	Commercial (GCOS)	Pilot Plant (Syncrude)
Product yields, wt. %				
H <sub>2</sub> S	1.2			
hydrocarbon gases <sup>a</sup>	7.0			
total gases <sup>a</sup>		8.3	7.9	6.7
gasoline <sup>b</sup>	15.4	12.1	12.7	10.9
kerosene		10.1	15.0	22.6
gas oil	55.0	41.4	36.2	36.5
fuel oil		4.2	6.0	--
coke	21.0	22.7	22.2	23.2
unaccounted	0.4	1.3		
Gas composition, mole %				
H <sub>2</sub>	11.0	24.2		
CH <sub>4</sub>	47.1	32.9		
C <sub>2</sub> H <sub>4</sub>	1.8	2.3		
C <sub>2</sub> H <sub>6</sub>	14.2	11.6		
C <sub>3</sub> H <sub>6</sub>	6.1	3.4		
C <sub>3</sub> H <sub>8</sub>	11.7	7.6		
C <sub>4</sub> H <sub>8</sub>	3.6			
C <sub>4</sub> H <sub>10</sub>	4.5	0.6		
H <sub>2</sub> S and others		17.4		
Reference	[24]	[41]	[23]	[64]

<sup>a</sup> C<sub>4</sub> and lighter. <sup>b</sup> C<sub>5</sub> and heavier.

Note: All yields based on whole bitumen. Feed is whole bitumen except Syncrude data which refer to topped bitumen feed.

TABLE 15

PRODUCT INSPECTIONS OF  
DELAYED COKING OF BITUMEN

Inspection	Scale of operation							
	Pilot plant		Commercial design basis			Pilot Plant (Syncrude)		
	Gasoline	Gas oil	Naphtha	Kerosene	Gas oil	Naphtha	Kerosene	Gas oil
Wt. % of Coker distillate	19.5	69.6	16.5	13.7	51.8	10.9	22.6	36.5
Gravity, °API	51.9	16.6	46.8	32.9	18.3	55.8	27.3	15.7
Sulfur, wt. %	1.86	4.04	2.2	2.7	3.8	1.85	2.7	3.7
Bromine no.	80	47	61	36	20	70	14	12
Nitrogen, total, ppm			150	400	2000	120	510	2980
FIA, vol. %								
aromatics			19	39.2	62.1			
olefins			32	14.4	2.0			
paraffins and naphthenes			49	46.4	35.9			
Distillation temperature, °F								
ibp	126	443	180	380	515	180	380	650
5%	165	466	202	396	530			
10%	186	486	220	409	550			
30%	232	550	268	428	600			
50%	275	621	295	441	645			
70%	315	600	314	458	697			
90%	358	715	347	477	780			
95%			360	490	807			
end pt	400	760+	400	535	850	380	650	925
recovery, %	98.5	97.5						
Viscosity, 100°F, SSU		70.8						
Reference	24	24	41	41	41	64	64	64

Note: All yields based on whole bitumen. Feed is whole bitumen except Syncrude data which refer to topped bitumen feed.



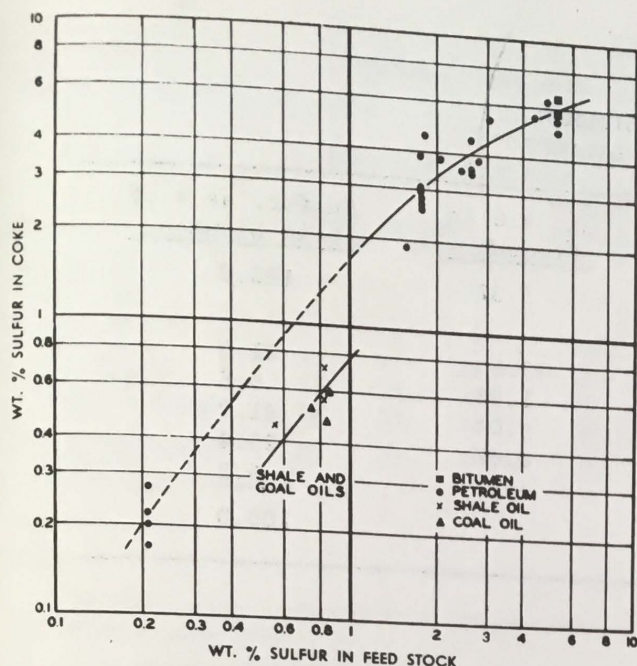


Fig. 38 Sulfur Contents of Coke Produced by Thermal Cracking, Source [24]

### Visbreaking

Visbreaking is a relatively mild conversion process. Feed is heated in a pipestill (as for delayed coking) and then immediately (or after a brief residence time) quenched. Tables 19 and 20 summarize yields and brief product inspections for visbreaking of bitumen.

### Hydrovisbreaking

Hydrovisbreaking is a general (and not very descriptive) term for a process in which feed is heated, contacted with hydrogen under pressure for some relatively long residence time, then quenched and distilled. Any individual variant must, of course, be defined by its process conditions. The hydrogen inhibits coking and may, in the presence of a catalyst, provide some desulfurization.

Thermal hydrovisbreaking has been studied by the Mines Branch [62,63]

## FLUID COKER

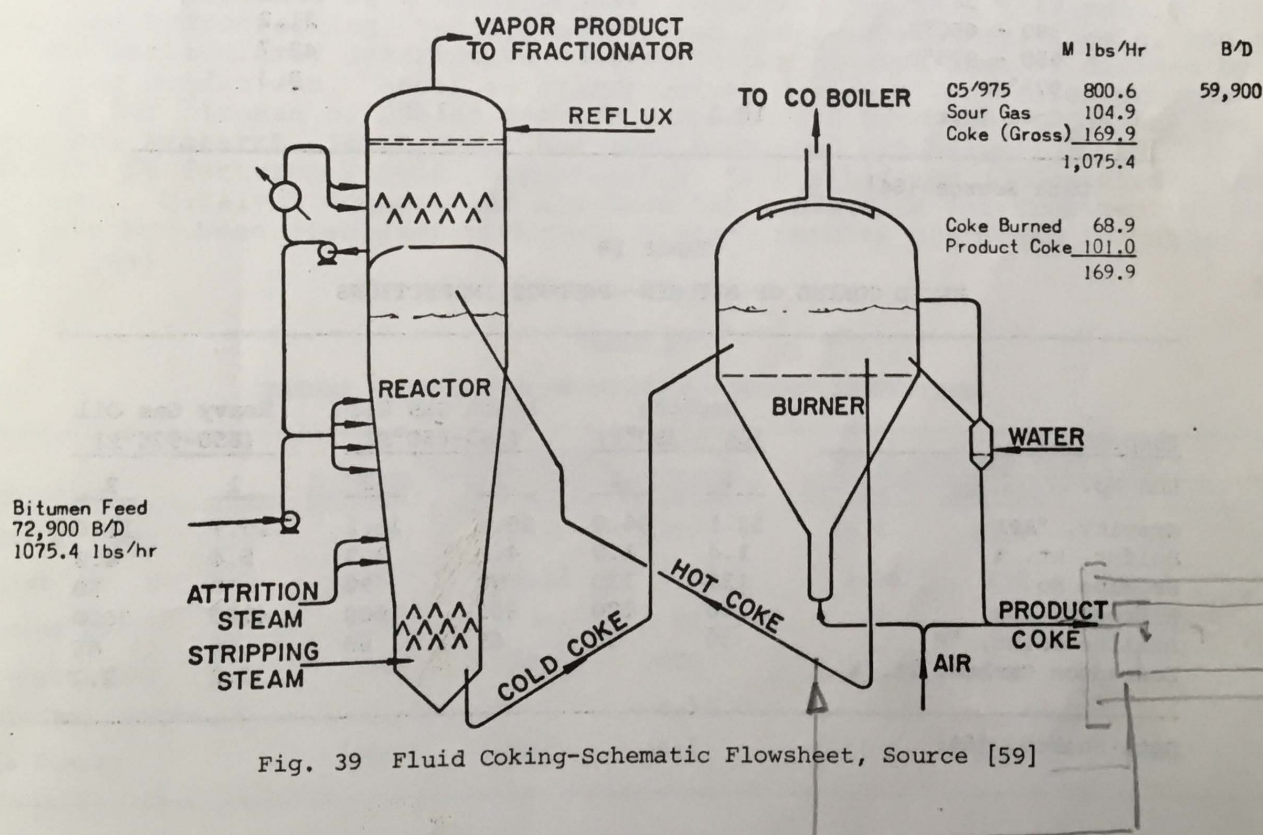


Fig. 39 Fluid Coking-Schematic Flowsheet, Source [59]



TABLE 16  
DELAYED COKING OF BITUMEN  
PILOT PLANT SULFUR BALANCE

	Product yield Wt. %	Wt. % S in Product	Sulfur, as % of S in Bitumen
Bitumen Charge	100.0	5.32	100.0
Products			
C <sub>4</sub> & Lighter Gas	8.2	13.8	21.2
Debutanized gasoline	15.4	1.86	5.5
Gas oil distillate	55.0	4.04	41.7
Coke	21.0	6.42	25.4
Unaccounted for	0.4	---	6.2
Total	100.0		100.0

Data Source, [24]

TABLE 17  
FLUID COKING OF BITUMEN--PRODUCT YIELDS

Run No.	1		2	
	Wt. %	Vol. %	Wt. %	Vol. %
Product Yield				
C <sub>3</sub> - Gas	9.1		7.9	
C <sub>4</sub>		3.6		1.5
C <sub>5</sub> - 380°F		19.1		11.5
380 - 650°F		26.6		21.2
650 - 975°F		35.4		42.7
975°F+		76.7		9.3
Coke (net)	10.0		7.3	

Data Source [64]

TABLE 18  
FLUID COKING OF BITUMEN--PRODUCT INSPECTIONS

Inspection	Naphtha (C <sub>5</sub> - 380°F)		Light Gas Oil (380-650°F)		Heavy Gas Oil (650-975°F)	
	1	2	1	2	1	2
Run No.						
Gravity, °API	52.1	56.0	25.8	26.1	10.7	11.0
Sulfur, wt. %	1.4	1.0	4.1	3.3	5.4	4.8
Bromine No.	130	130	90	90	30	30
Nitrogen, ppm	160	100	800	600	4100	3000
Aniline Point, °F	50	50	65	65	85	85
Conradson Carbon, wt. %					3.2	2.2

Data Source, [64]



TABLE 19  
THERMAL VISBREAKING OF BITUMEN--PRODUCT YIELDS

Product Yields, (wt. or vol. %)	SYNCRUDE PILOT PLANT <sup>1/</sup>				MINES BRANCH <sup>2/</sup>						
	Whole Bitumen			Topped	Whole Bitumen			Topped Bitumen	Diluted Bitumen		
	-----wt. %-----			Bitumen	-----vol. %-----			(+ 750°F)	(5 vol. % Coke		
				wt. %				% except where W = wt. %-----	Kerosene)		
C <sub>4</sub> - gas	1	3	3	1	≤ 1W	3.2W	5.5W	1W	2W	15.0	23.8
C <sub>5</sub> - 400°F	3	7	9	4			15.5			31.7	36.0
400-650°F	22	21	25	21			32.9			37.3	29.2
650-1000°F	32	35	32	40			34.6			16.0	11.0
1000° + resid.	42	34	30	34	31	24	15.0	38	27		
Wt. % Conversion (1000°F)	24	39	46	39	33	46	67	46	60	63	75
Temperature, °C					380	410	430	390	430	430	440
Pressure, psig					1000	1000	1000	1000	1000	1000	1000
LHSV					1.0	1.0	1.0	1.0	1.0	1.0	1.0

1/ Date Source [64]

2/ Data Source [63]

using a 150 cc continuous flow reactor. In this process no (heterogeneous) catalyst was used. However, the investigators believed that low-boiling diluents served the role of a homogeneous catalyst or hydrogen transfer agent to inhibit coking. Tables 19 and 20 summarize a few results from the rather complete study.

In the presence of a heterogeneous catalyst, hydrogen treatment of bitumen is called hydrocracking, hydrotreating, and hydrovisbreaking. Again, the names are not particularly descriptive, and any given process must be defined by its operating conditions. H-Oil is a proprietary residuum conversion process offered for license by Cities Service Research and Development Company and Hydrocarbon Research, Inc. H-Oil has been described extensively in the literature [46,60]; it features liquid phase reaction in a fluidized ("ebullated") bed of catalyst. Catalyst composition and reaction conditions for treatment of bitumen have not been disclosed; however, typical results are given in Tables 21 and 22 [64].

TABLE 20  
THERMAL VISBREAKING OF BITUMEN--PRODUCT INSPECTIONS

Inspection	TYPICAL PRODUCT			WHOLE BITUMEN (63% CONV.)		
	C <sub>5</sub> -380°F	380-650°F	650-1000°F	C <sub>5</sub> -380°F	380-650°F	650-990°F
Gravity, °API	54	25.8	13.2	48.5	25.7	10
Sulfur, Wt. %	2.02	2.11	3.91	1.38	2.5	4
Bromine No.	115	38	20			
Nitrogen, ppm	110	450	2800			
Conradson Carbon, %			0.23			
Data Source	[64]	[64]	[64]	[62]	[62]	[62]



TABLE 21  
CATALYTIC HYDROVISBREAKING OF BITUMEN  
PRODUCT YIELDS

Product Yield, Vol. %	H-Oil			Mines Branch	
C <sub>5</sub> - 380°F	16	18.6	21	10	6
380-650°F	43	45	46.8	38	20
650-975°F	26.3	26	25.8	38	43
975°F +	16	11.3	7.5	24	28
Vol. % Conversion (975°F)	68	77.5	85	48	39
Data Source	[64]	[64]	[64]	[62]	[62]

Hydrovisbreaking of bitumen was studied by the Mines Branch [62] using a fixed bed, liquid phase, continuous upflow reactor configuration. Catalyst was a commercial Cobalt Molybdate/alumina, formed into 3/10" x 3/16" pellets (Nalco Chemical Co.: 12.5% MoO<sub>3</sub>, 3.2% CoO, 280 m<sup>2</sup>/g). Typical results from this rather extensive study are summarized in Tables 21 and 22.

Direct hydrogenation of bitumen has also been tested by the Mines Branch of the Federal Canadian Government [43] in the same fixed bed continuous flow reactor, using a top feed trickle bed arrangement. This study, as that on hydrogenating coker distillate (below), was aimed more particularly at desulfurization than conversion. The feed consisted of Abasand cold water process bitumen and blends of this bitumen with a distillate produced at the Bitumount pilot plant. The blend used in most of the tests is described in Table 23. The catalyst in the fixed bed reactor was the same (Union Oil Company Type N-5) cobalt-molybdena on alumina catalyst used in the high pressure hydrogenation tests on coker distillate. The catalyst was used in two forms: as received (oxide form), and sulfided (850°F, 1 atmosphere H<sub>2</sub>S, 1 hour).

The effect of temperature on sulfur removal is shown by curve 3 on Figure 40. Note that while the desulfurization achieved is comparable to that possible

TABLE 22  
CATALYTIC HYDROVISBREAKING OF BITUMEN  
PRODUCT INSPECTIONS

Inspection	H-OIL (75% Conversion)			MINES BRANCH (48% Conversion)		
	C <sub>5</sub> -380°F	380-650°F	650-975°F	C <sub>5</sub> -380°F	380-650°F	650-990°F
Gravity, °API	51	28.6	10.5	57.2	29.3	17.8
Sulfur, wt. %	1.0	1.0	3.47	.18	.45	1.0
Bromine No.	48	25	12			
Nitrogen, ppm	270	800	3200			
Data Source	[64]	[64]	[64]	[62]	[62]	[62]



TABLE 23  
HYDRODESULFURIZATION OF DILUTED BITUMEN

Inspection	Feed	Oxide catalyst <sup>a</sup>				Sulfided catalyst <sup>b</sup>				
		Whole product	Product fractions			Whole product	Product fractions			
Whole product, vol. %			60	17	23		47.2	12.8	13.3	10.9 15.8
Gravity, °API	10.1	28.4				32.5				
Sulfur, wt. %	4.02	0.93	trace	0.18	2.85	1.97	trace	0.04	0.12	0.27 4.08
Distillation temperature, °F										
ibp				660	800+		480	540	660	800+
5%	385	230								
10%	480	310				255				
30%	674	485				390				
50%		600				480				
70%		720				625				
90%										
95%										
end pt			660	800			480	540	660	800
recovery, at 800°F, %	46.5	76.8				84.2				

<sup>a</sup>Pressure, 2000psig; temperature, 810°F; LHSV, 0.5 vol/(vol)(hr). <sup>b</sup>Pressure, 2000psig; temperature, 806°F; LHSV, 0.5 vol/(vol)(hr).  
Data Source [43]

with coker distillate, much more severe operating conditions are required. This requirement of increased treating severity can be illustrated in a different way by comparing Figures 41 and 43. These two figures show the amount of sulfur reduction achieved for a given amount of specific gravity reduction. Hydrogen consumption data were not provided for the bitumen hydrogenation tests. If, however, hydrogen consumption follows specific gravity reduction for the bitumen hydrogenation as it did for coker distillate (Figure 43), then because a given sulfur reduction requires more specific gravity reduction for diluted bitumen than for coker distillate, it is reasonable to assume that the same sulfur reduction also requires more hydrogen consumption. The economics of hydrotreating are directly and largely influenced by the amount of hydrogen chemically consumed.

Catalyst life for hydrotreating diluted bitumen was tested in several 100-hour continuous runs. Catalyst in the sulfided form showed a deactivation rate (LHSV = 0.5, 840°F, 2000 psig) of  $5.5 \times 10^{-4}$  SG units/hour. A similar test at 1.0 LHSV showed double this deactivation rate. Extrapolating these data, the rate of 2.0 LHSV would have been  $22 \times 10^{-4}$  SG units/hour or 15 times the corresponding rate (LHSV = 2, 896°F, 2000 psig) observed for hydrotreating coker distillate. The deactivation rate for coker distillate was observed using the catalyst in the oxide form. When the catalyst is used in the oxide form for treating diluted bitumen, no regular increase in specific gravity with time is observed in 70 hours (850°F) or in 100 hours (800°F). O'Grady and Parsons [43] speculate that the greater cracking activity of the sulfide form of the catalyst leads to more rapid coke buildup on the catalyst. At temperatures of 800°F and below, the oxide catalyst form has low enough cracking activity that coke precursors can be washed away from the catalyst surface by the liquid phase portion of the reaction medium. Inspections on products and



Fig. 40  
Catalytic Hydrodesulfurization,  
Temperature Effect

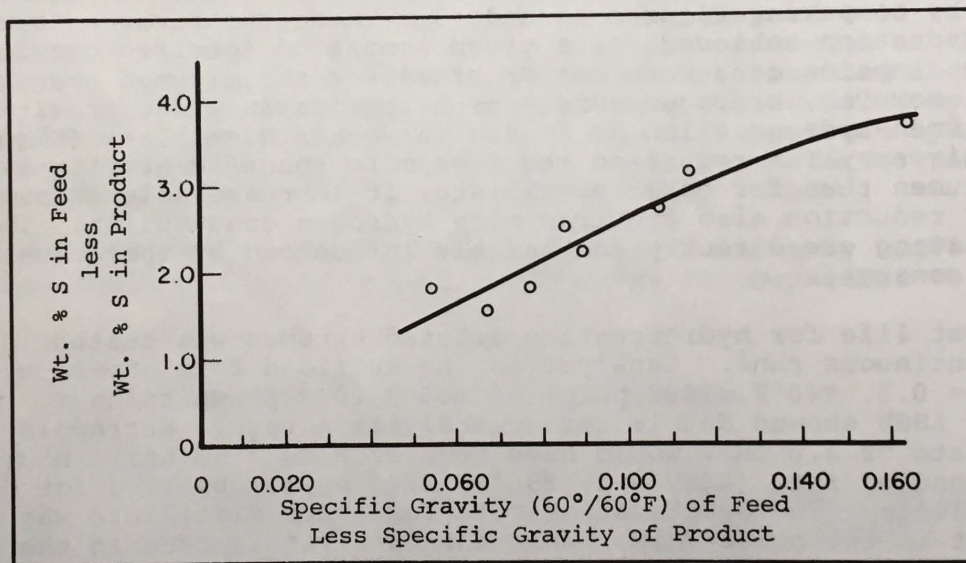
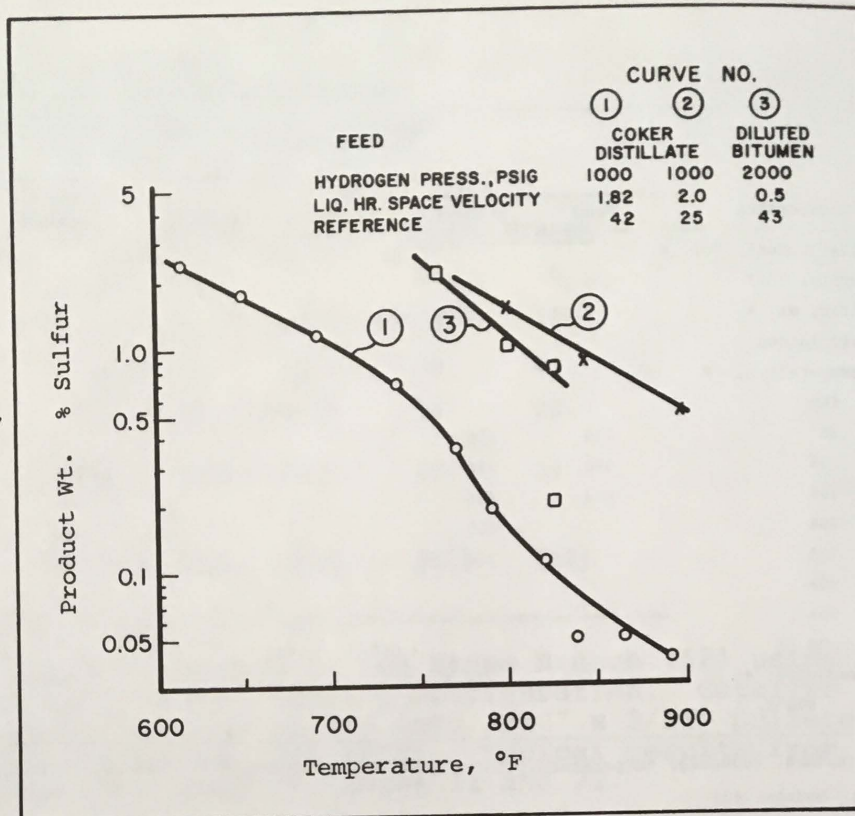


Fig. 41  
Catalytic Hydrotreating of Bitumen  
Source [43]



product fractions are summarized in Table 23, which illustrates the greater cracking activity of the sulfide catalyst form (480°F vs. 600°F mid-boiling point in the product). The oxide catalyst form is somewhat more active for sulfur removal at equivalent operating conditions; however, both catalysts yield an 800°F+ residuum which is only slightly, if at all, improved in sulfur content. On the other hand, brief tests showed that this residuum is no more refractory than the (undiluted) feed bitumen, and thus might be recycled if desired.

#### Refining of Bitumen: Distillate Treatment

All proposals to recover oil from the Athabasca tar sands include the step of desulfurizing the synthetic crude oil product. Because the sulfur is so well distributed throughout the boiling range, catalytic hydrodesulfurization is the only process which has been seriously considered. The Mines Branch of the Federal Canadian Government has maintained an ongoing research program concerning hydrotreating of coker distillates [42,25] from bitumen and, more recently, of bitumen itself [43].

The feed material used [42] in a series of low pressure hydrogenation tests was a coker distillate produced from cold water process Athabasca bitumen. The feed was a black oil of 3.5 wt.% sulfur and a specific gravity of 0.936 (19.7°API). The feed for a later series of higher pressure tests [25] was similarly produced and is described in more detail in Table 6 on page 25. Catalysts used were cobalt-molybdena on alumina, supplied by the Union Oil Company of California as 1/8" x 1/8" pellets. Catalyst used in the low pressure tests was designated type N; high pressure tests used a catalyst designated type N-5. The effect of operating temperature on sulfur removal is shown in Figure 40. The effects of operating pressure and temperature on sulfur removal are shown in further detail in Figure 42. Other measures of the extent of hydrogenation are specific gravity reduction and hydrogen consumption. In Figure 43, both sulfur removal and hydrogen consumption are related to specific gravity reduction. Aitken [25] expressed the catalyst deactivation rate by using the term  $\Delta SG / \Delta \theta$ . In continuous operation at fixed feed and operating conditions, specific gravity (SG) increased approximately linearly with time ( $\theta$ ) over a run length of 10-200 hours. Catalyst deactivation rate was expressed as:

$$\Delta SG / \Delta \theta = 1.25 \times 10^6 / P^{3.1}$$

(Temperature  $\Delta$  896°F)  
 (L.H.S.V. = 2.0)  
 (Pressure = 1000-3000 psig)

Where P = reaction pressure, psig

In order to take advantage of optimum operating conditions for various distillate fractions, the GCOS Coker distillate is treated as three separate fractions: naphtha, kerosene and gas oil. GCOS used the Unifining process (Universal Oil Products Company), but operating conditions have not been published. In the operation proposed by Shell Canada Ltd., feed is to be treated in two fractions, a naphtha-kerosene and a heavy gas oil. Inspections on feeds and products of these desulfurizing operations are summarized in Table 24.



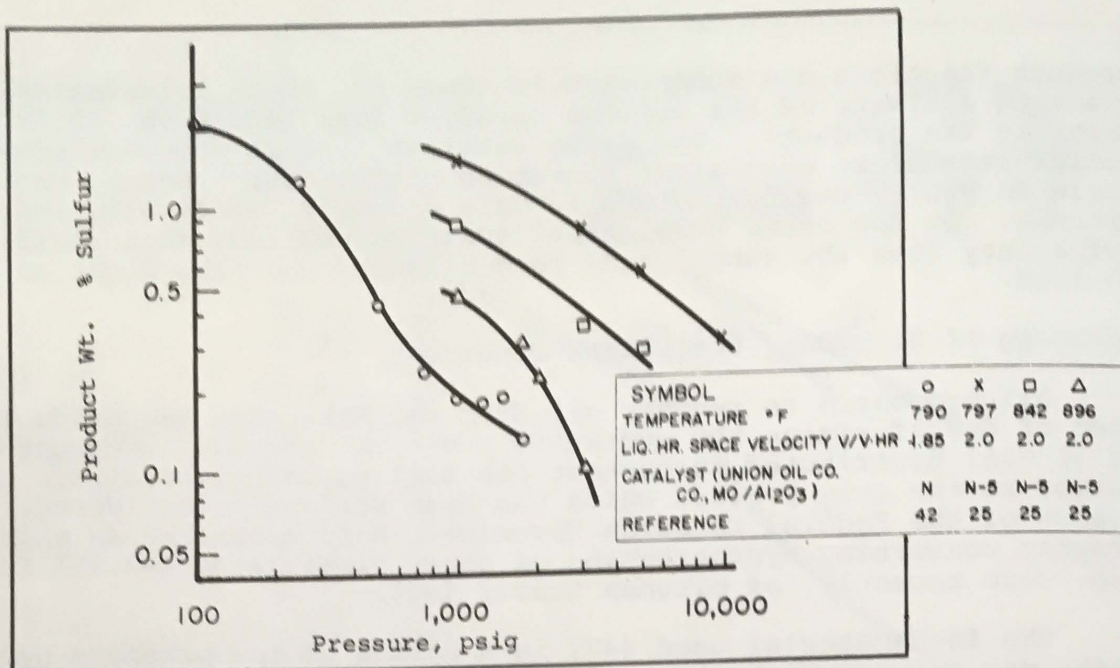
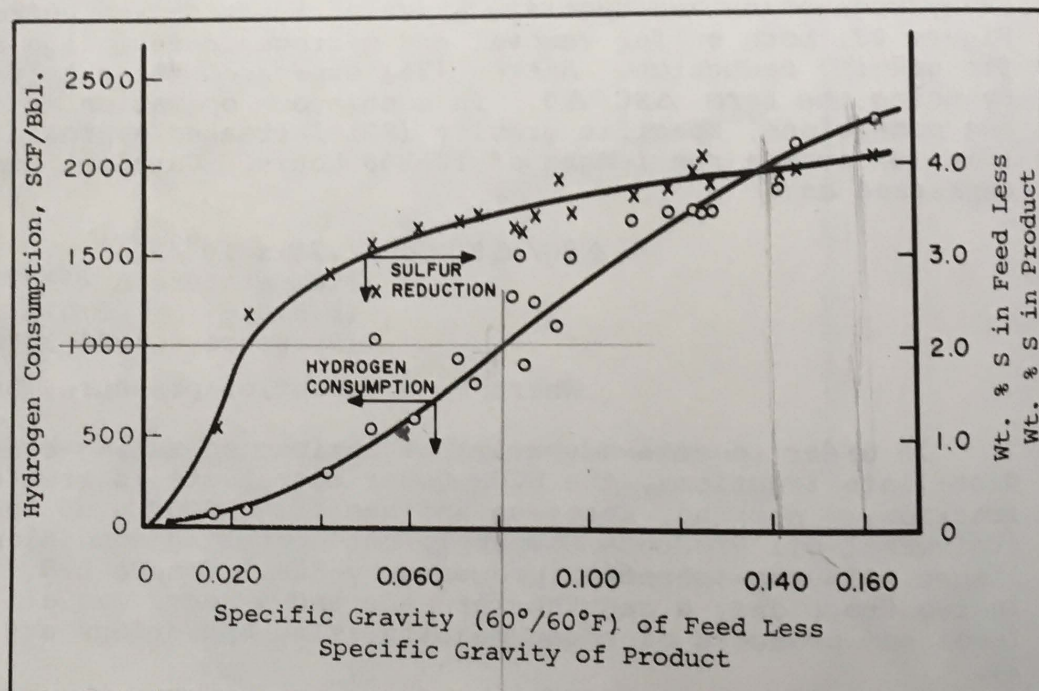


Fig. 42 Catalytic Hydrodesulfurization,  
Pressure Effect

Fig. 43  
Catalytic Hydrotreating  
of  
Coker Distillate  
Data Source [25,42]



0.08

API S.G.  
28.5 = 8844  
18.3 = 944  
- 884  
1.060  
- 7.364  
- 7.856  
1.07%



TABLE 24  
HYDRODESULFURIZATION OF COKER DISTILLATE FRACTIONS

Inspection	GCOS									Shell Canada, Ltd.			
	Naphtha			Kerosene			Gas oil			Naphtha and kerosene		Heavy gas oil	
	Product			Product			Product			Product		Product	
	Feed	Pilot	Com.	Feed	Pilot	Com.	Feed	Pilot	Com.	Feed	Product	Feed	Product
Coker distillate, wt. %	16.5			13.7			51.8						
Synthetic crude, vol. %		30.6	30.8		19.0	27.2		50.4	42.0				
Gravity, °API	46.8	50.9	55.3	32.9	39.7	38.6	18.3	28.7	27.5	28.4	41.5	10.6	20.2
Sulfur, ppm	22,000	50	15	27,000	50	50	38,000	800	410	29,800	500	41,500	5,100
Nitrogen, total, ppm	150		2*	400	1	50*	2,000	trace	500*	600	100	22,900	1,700
PFA, vol. %, aromatics	19	18		39.2	13.8	12.7	62.1	29.8	25.3				
olefins	32			14.4	<1.0		2.0						
paraffins and naphthenes	49			46.4	85.7		35.9						
Distillation temp, °F													
ibp	180	174	162	380	388	358	515	499	498				
5%	202	260	194	396	398	385	530	512	526				
10%	220	274	206	409	402	398	550	522	540				
30%	268	282	238	428	411	418	600	561	568				
50%	295	296	278	441	415	438	645	611	588				
70%	314	310	316	458	423	460	697	655	615				
90%	347	334	369	477	433	496	780	740	675				
95%	360	344	396	490	448	513	807	785	706				
end pt	400	366	462	535	468	533	850	869	715				
recovery, %								90					
Viscosity, 100°F, cSt					1.8								
Operating conditions													
inlet pressure, psig	800			1,500			1,500			1,200		1,500	
outlet temperature, °F										725		725	
LHSV, vol/(vol) (hr)										1.0		1.0	
hydrogen consumption, scf/bbl										700		1,000	
Reference	41	23	23	41	23	23	41	23	23	21	21	21	21
					51			51					

\*Typical Properties

7.364  
6.810  
554  
7.364 = 1.08



## COMMERCIAL VENTURES

Following issuance of the Blair report in 1950, there was a spate of activity in applications for leases in the Athabasca tar sands. Between 1950 and 1955, exploration leases covering a large proportion of the tar sands were issued. These leases generally provided exploration rights only and could be maintained annually by payment of a nominal sum. Exploration leases now cover practically the entire deposit.

Serious pilot plant efforts were undertaken beginning in about 1955. Over the years, these efforts have led to seven applications for commercial production from the Athabasca tar sands deposit [31,32,44,45,56-59,61,69]. Those of Great Canadian Oil Sands, Limited and the Syncrude group have been approved. GCOS is now in commercial production while Syncrude projects commercial startup in 1977 or 1978. Three of the applications (Shell in situ, Cities Service and Muskeg) were either withdrawn or rejected and the two most recently filed (Shell mining and the AOP group) are still pending. Table 25 is a summary comparison of the major points contained in the applications. Each proposed or existing venture is discussed in greater detail in the following pages.

### GREAT CANADIAN OIL SANDS, LIMITED

Great Canadian Oil Sands, Limited was formed in 1953 from the holdings of Oil Sands, Limited. GCOS is in a direct line of descent from the Bitumount pilot plant. In 1953 GCOS's stock-in-trade was a hot water bitumen extraction process based on the earlier Bitumount pilot work. But again repeating the often-told story, GCOS needed financial backing. At about the same time, Sun Oil Company became interested in the tar sands through Sun's Canadian exploration work. Sun subsequently acquired a 75% interest in Lease No. 4 in the Mildred-Ruth Lakes area, along with Abasand Oils, Limited, the original lease holder.

From the time of the original exploration work of S. C. Ells, the Mildred-Ruth Lakes area was reputed to be a prime candidate for a tar sands mining venture. The drilling program [50] of 1942-47 confirmed this and Abasand later acquired Lease No. 4 after World War II. GCOS obtained an option to sublease from Sun and Abasand in 1957. In 1960, GCOS applied [31] to the



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Shell Canada, Ltd.	130,000	100,000	---	In situ	API separator	Electrical dehydrator	Thermal cracking	Hydrodesulfurization	Application filed 1962, withdrawn 1968	[21] [45]
Cities Service Athabasca <sup>1/</sup>	134,000	100,000	\$274 million	Bucket wheel excavators	Dense phase process <sup>2/</sup>	Thermal dehydrator	Fluid coking	Hydrodesulfurization	Application filed 1962, later re-jected	[20] [44]
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Muskeg Oil Company <sup>6/</sup>	8,000	---	\$15.69 million	In situ	Gravity settlers, diluent recovery	-----Not included in proposal-----			Application filed 1968, withdrawn 1970	[56]
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10/ Initial production rate is 104,580 BPCD with proposed start-up in 1977 or 1978.

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Dedication ceremonies for the commercial plant were held on September 30, 1967. Figure 44 illustrates the hot water extraction process used by GCOS



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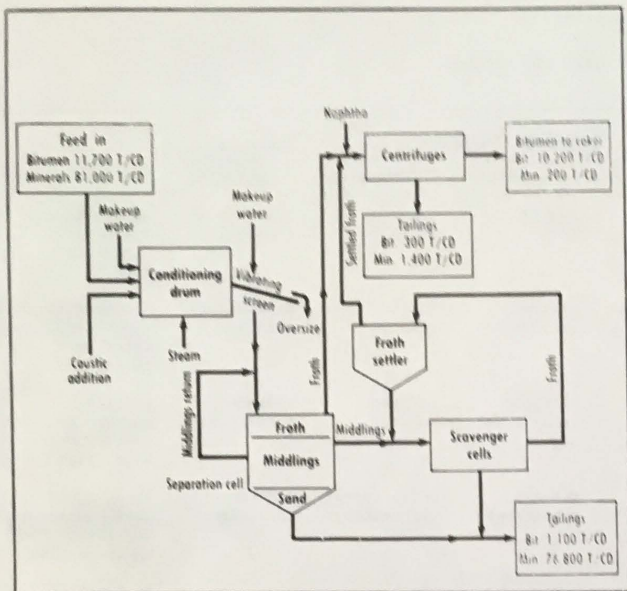


Fig. 44 GCOS Bitumen Recovery Process, Source [41]

for recovery of bitumen from the tar sands. Figure 45 is an overall flow sheet and material balance for the project. Startup of the GCOS project was protracted but this was not altogether unexpected for a refinery that is not only a grass roots operation located in a wilderness area, but is also the first of its kind. Initial commercial operation proved out the design bases [23]. For the year 1972, synthetic crude production exceeded the 45,000 B/D design rate by over 6,000 B/D. This rate set a new production record and marked the first year design production was achieved. In late 1973, GCOS obtained approval from the Energy Resources Conservation Board for an allowable production increase to 65,000 BPCD; Figure 46 reflects the revised material balance.

### CITIES SERVICE ATHABASCA AND SYNCRUDE CANADA, LIMITED

The Syncrude Group has led a second chain of efforts, which also began in the mid 1950's, but with a somewhat less direct connection to the Bitumount pilot plant. The Alberta government ultimately acquired ownership of the Bitumount pilot plant but had no use for the property and later sold it to

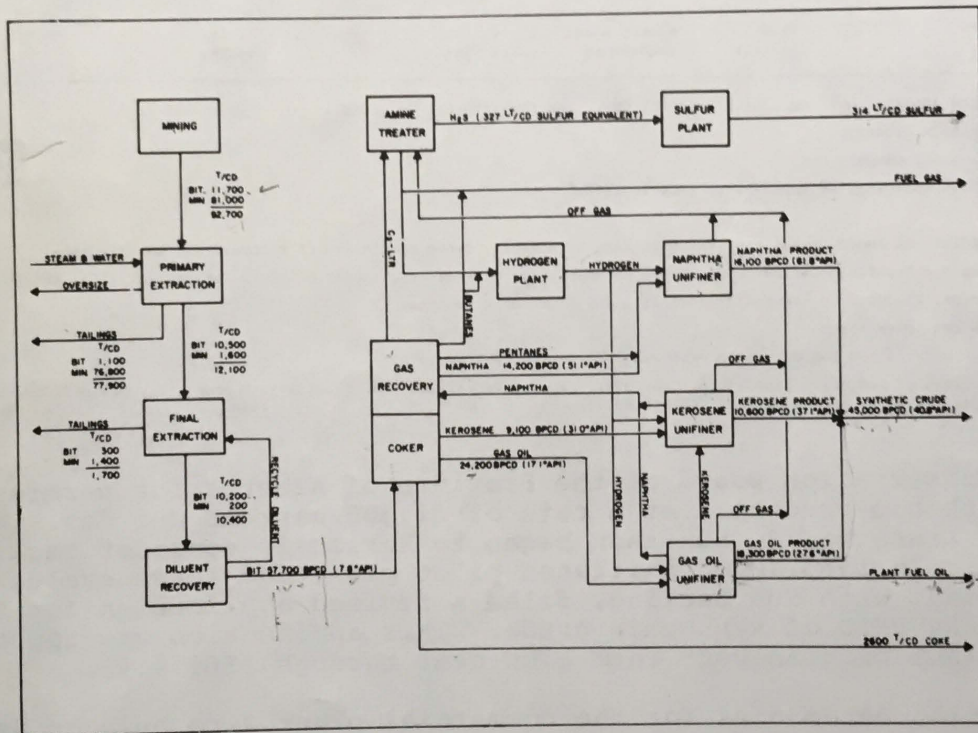


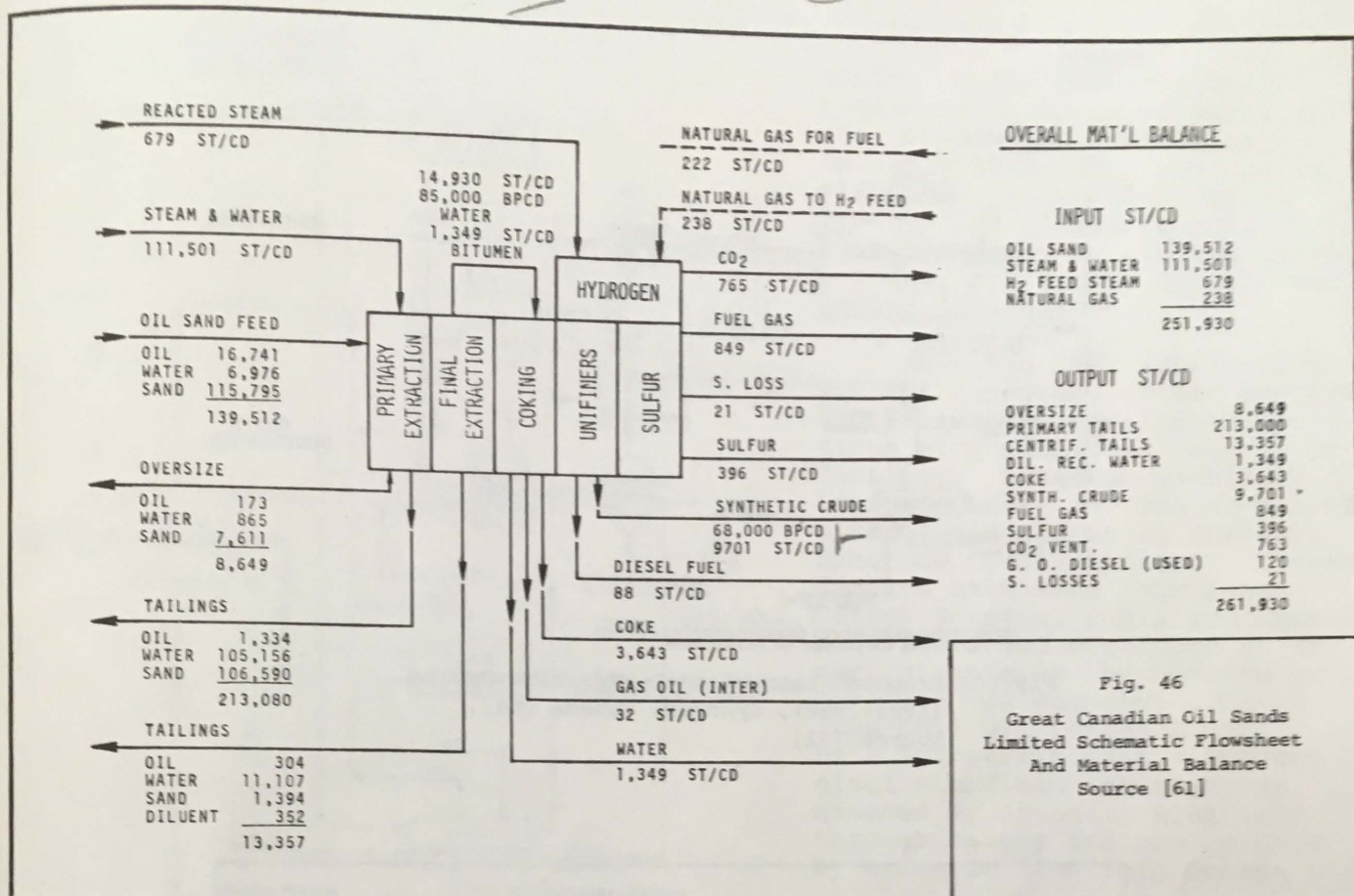
Fig. 45 GCOS Process, Source [14]

45,000  
57,700  
7890



$$\frac{9701}{16.741} = 5890$$

(18)



Can-Amera and Royalite Oil Company, Limited. Royalite subsequently joined a group led by Cities Service Athabasca, Limited, which included Imperial Oil Limited and Richfield Oil Corporation. Further pilot plant work was carried out briefly in 1958 at the Cities Service laboratory in Lake Charles, Louisiana. In 1959, an extensive pilot facility was opened near Mildred Lake on the west bank of the Athabasca River, some 25 miles north of Fort McMurray. This pilot plant was operated from 1959 to 1962 [20] and resulted in the Cities Service Athabasca application in 1962 [44].

The Cities Service bitumen recovery scheme was also a hot water extraction process; the flow sheet (showing rates as revised by Syncrude Canada Ltd. in 1968 [32] is summarized in Figure 47. Bitumen upgrading is shown in Figure 48. The process is essentially the same as that proposed by GCOS, except that fluid coking is used instead of delayed coking. Fluid coking is a coking process offered for license by Esso Research and Engineering Company, which is a part of the New Jersey Standard Oil Company family as is Imperial Oil, Limited. This process should not be confused with direct coking of tar sands as studied by the Mines Branch of the Federal Canadian government. This latter process also uses a fluidized solids technique.

At the time of the Cities Service Athabasca application, the Oil & Gas Conservation Board had in effect a policy whereby production from the tar sands was limited to 5% of the commercial crude oil production of the Province of Alberta. Under this restriction, the GCOS application could be allowed but



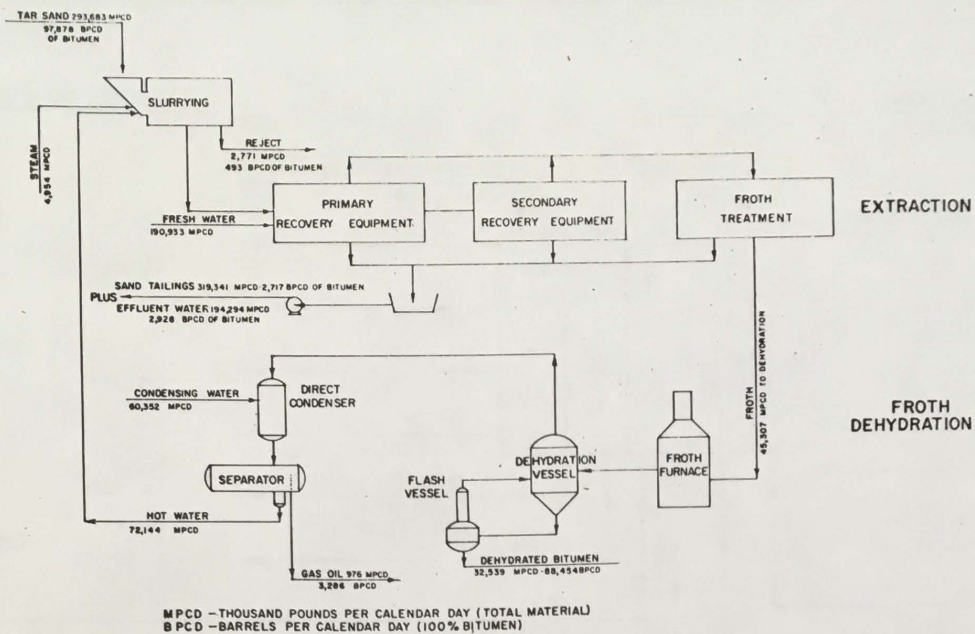


Fig. 47 Proposed Extraction-Dehydration System  
(1962-1968), Syncrude Canada Ltd.,  
Source [32]

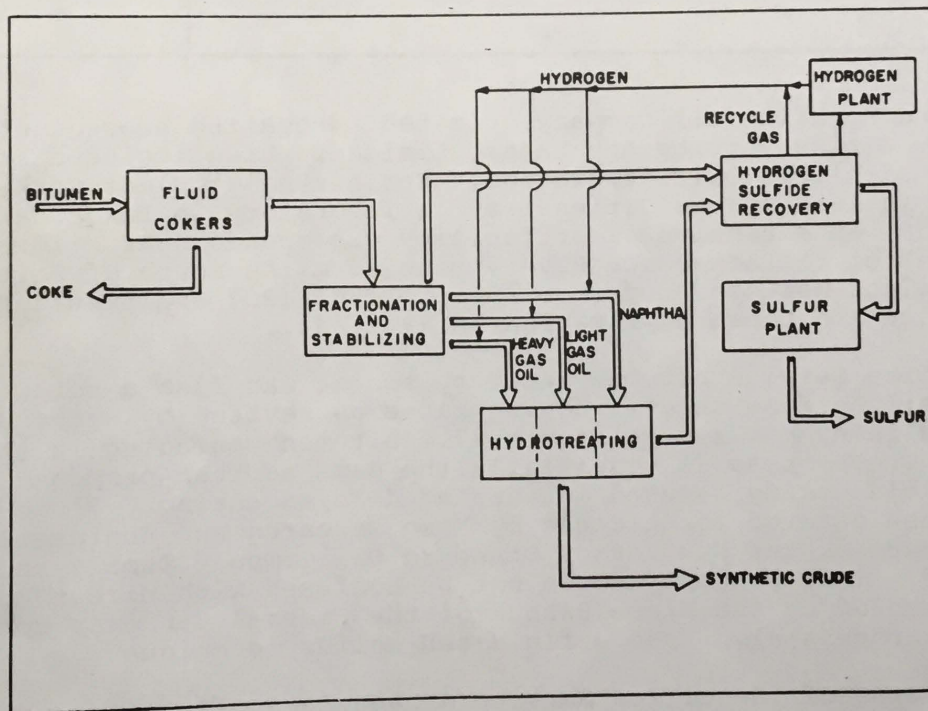


Fig. 48 Cities Service Athabasca Ltd. Proposed  
Bitumen Upgrading Process (1962),  
Source [20]



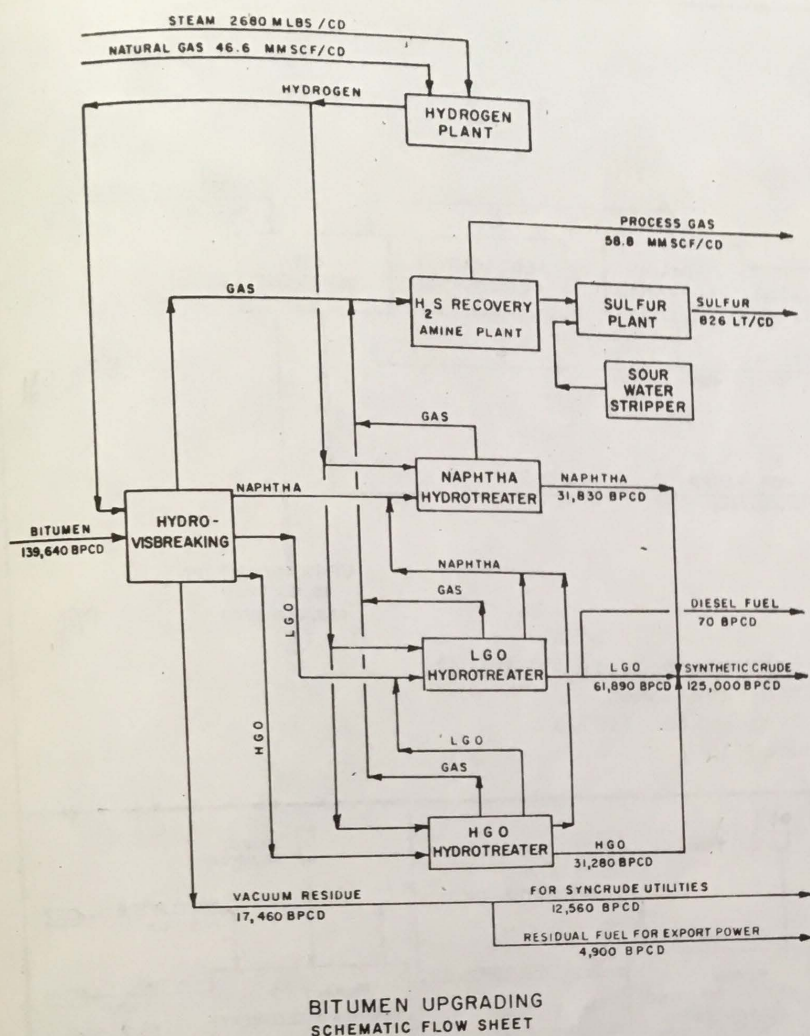


Fig. 49 Proposed Bitumen Upgrading Process  
(1968-1971) Syncrude Canada Ltd.  
Source [58]

the elimination of coking in favor of H-Oil, a residuum hydrotreating process. The H-Oil process was developed jointly by Cities Service and Hydrocarbon Research, Inc. in the early 1960's. The flowsheet (with rates as revised in 1971) is shown in Figure 49.

Again the application was not approved and in 1969 an amended application was filed by the Syncrude group. Technical provisions of the 1969 application [57] were the same as in the 1968 filing [32], but the startup date was postponed from 1973 to 1976. In addition, it was demonstrated that the product could be marketed such that Alberta's conventional oil industry would not be adversely affected. This application was approved.

In 1971 the Syncrude group filed amendments to their approved application [58] wherein they asked permission to increase production to 125,000 BPCD. Substantial technical changes were also reflected in the amendments. In particular, the mine plan was revised from scrapers to dragline and unit trains. Figure 50 shows the proposed extraction process. By the early 1970's, it was

action on the applications of Cities Service and of Shell (each for 100,000 B/D) was deferred. In early 1968, the Province revised this limitation and increased the allowable production from tar sands to 150,000 barrels per day, subject to certain marketing limitations.

When the 1962 application was not approved, Cities Service Athabasca Ltd. terminated operations at the Mildred Lake pilot facility. Research continued in Edmonton under the leadership of a realigned operating company, Syncrude Canada Limited. Cities Service Athabasca (now Canada-Cities Service, Ltd.) and Imperial Oil Limited continued as 30% participants in the venture and Royalite Oil Company, Limited (now Gulf Oil Canada Limited) as a 10% participant. The original Richfield interest was assumed by Atlantic Richfield through merger and now is held by Atlantic Richfield Canada Ltd.

Under the new policy of the Oil and Gas Conservation Board, Syncrude submitted a revised application [32] early in 1968 for production of 80,000 BPCD. This application involved major changes in concept from the 1962 Cities Service Athabasca plan. One of the principal changes was



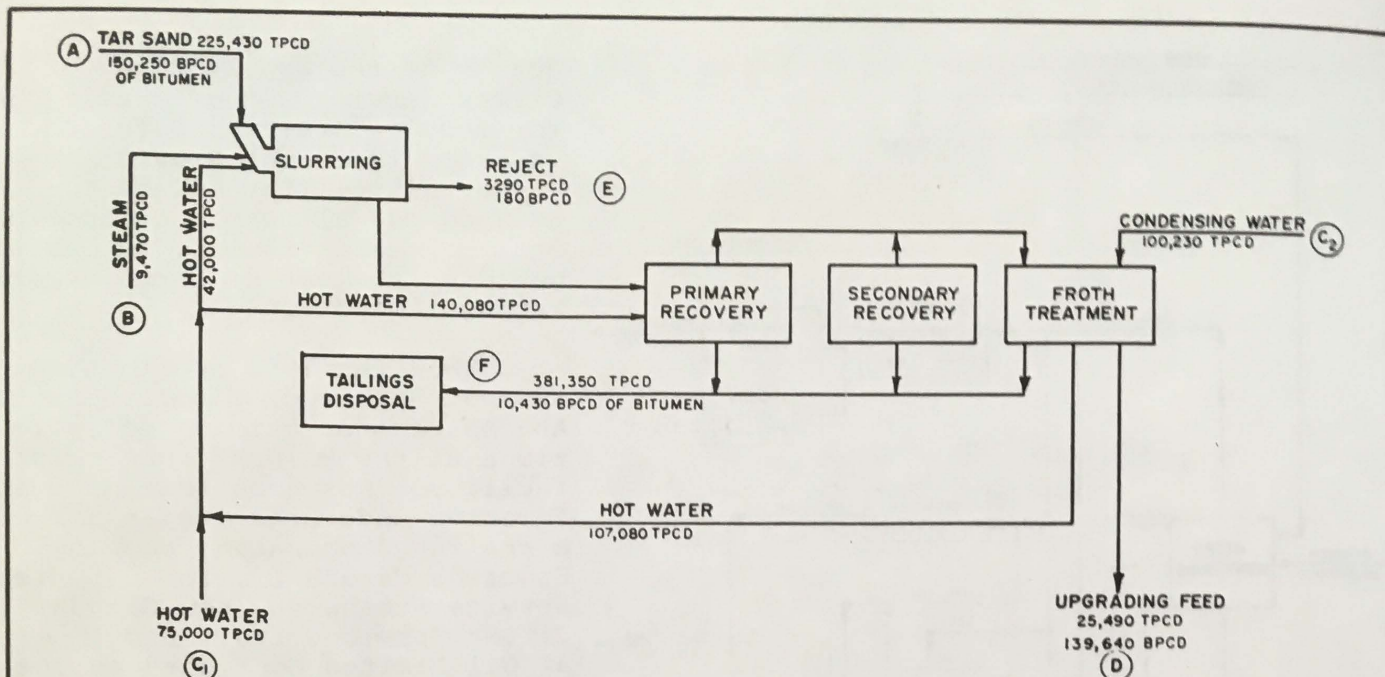


Fig. 50 Proposed Extraction-Froth Treatment  
Schematic Flow Sheet  
Syncrude Canada Ltd. (1971)  
Source [58]

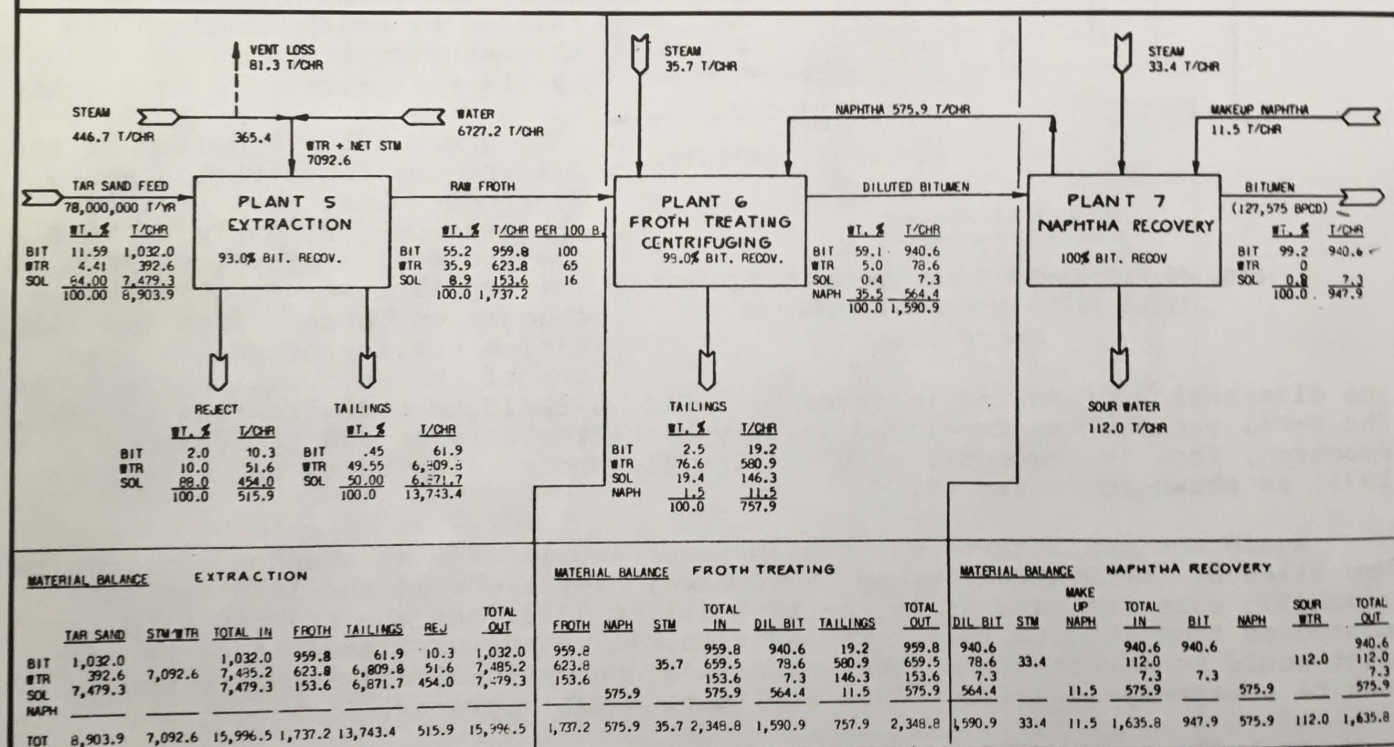


Fig. 51 Extraction, Froth Treating, Naphtha Recovery (1973)  
Syncrude Canada Limited  
Source [59]



apparent in Alberta (as it has now also become apparent in the U.S.) that the ratio of proved conventional reserves to production -- the life index -- was decreasing rapidly and that further decreases could reliably be expected. Government policy aims to maintain the life index at 12-13 years or above. Under this life index criterion, Syncrude's 1971 amendments were approved, but with the provision that Syncrude announce its intention to proceed with the project by August 31, 1973.

In March 1973, Syncrude applied to the Energy Resources Conservation Board (formerly Oil and Gas Conservation Board) for further technical changes in the project, including a switch from thermal dehydration to dilution and centrifuging for froth cleanup (Figure 51). Also, in the initial refining step, fluid coking replaced hydrovisbreaking (Figure 52). (Note: Figures 51 and 52 refer to an initial design case of 104,500 BPCD synthetic crude; the ultimate project size remains at 125,000 BPCD.) The most recent application states Syncrude's intention to proceed.

#### SHELL CANADA, LIMITED (IN SITU PROJECT)

Shell's process is based on their pilot plant work carried out between 1957 and 1962 [21,27]. This work included extensive field trials of two in situ processes: (1) surfactants and (2) dilute caustic solution, along with steam to emulsify the in-place bitumen. The latter process, called steam drive, is the one they proposed to commercialize. Shell's proposed bitumen refining scheme is summarized in Figure 53. This scheme is analogous to that of GCOS and Cities Service Athabasca, Limited with the exception that the thermal cracker produces a liquid pitch for use as refinery fuel rather than coke. The Oil & Gas Conservation Board deferred action on Shell's application (for 100,000 B/D); in 1968 Shell withdrew their application.

#### SHELL CANADA, LIMITED (MINING PROJECT)

In 1973, Shell Canada Ltd. and their oil sands co-venturer, Shell Explorer Ltd., applied to the Energy Resources Conservation Board for approval of a 100,000 BPCD mining-upgrading project in the Athabasca oil sands deposit area [69]. Figure 54 is a combined extraction and upgrading flow sheet depicting Shell's proposed project. As of early 1974, the Conservation Board had taken no action on Shell's latest application.

Shell's application anticipates the use of 75- to 90-cubic yard draglines for both overburden removal and tar sand mining. Shell's recovery scheme is based on the K. A. Clark hot water bitumen extraction process followed by vacuum flashing with the vacuum residue subjected to solvent deasphalting. The deasphalted residue constitutes fuel for a utility plant.

The vacuum gas oil is hydrotreated and the deasphalted oil is sent to a hydrocracker. The naphtha and gas oil streams from the hydrogenation units are then combined to produce a synthetic crude with a gravity of 30° API. Acid gas from the hydrogenation units is subjected to sulfur recovery in two, 3-stage Claus sulfur plants.

#### AMOCO CANADA LTD.

Muskeg Oil Company (now Amoco Canada Ltd.) applied in 1968 [56] to produce bitumen from the tar sands by an in situ process using a combination of forward combustion and water flood (COFCAW) developed in laboratory and field



Bit recovery Synchro = 92.9%  
 Upgrading = 86.8

Total =  $92 \times 86.8 = 79.1$

$92 \times 86.8 = 79.1$   
 $86.8 \times 91.1 = 79.1$

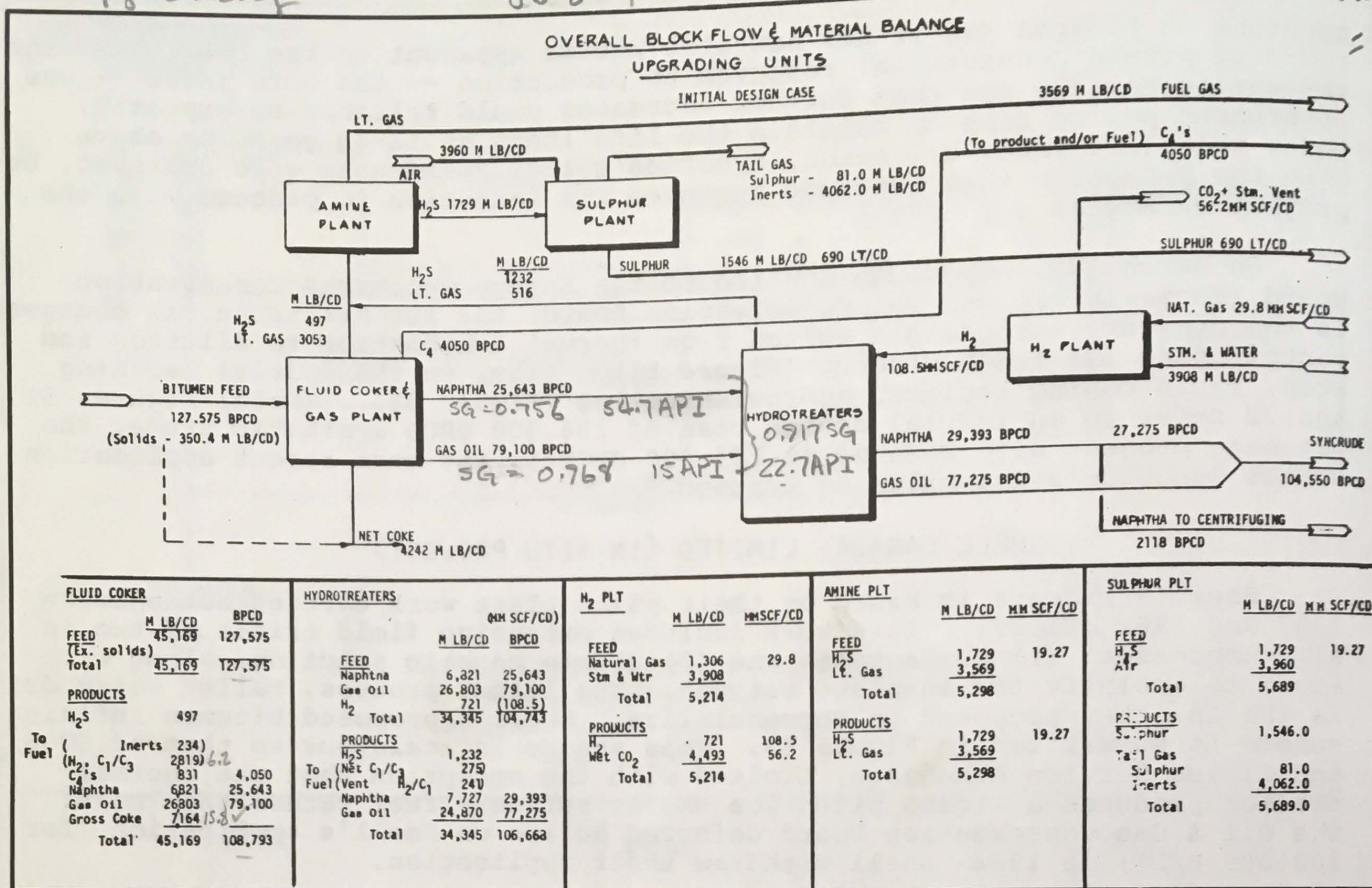


Fig. 52 Bitumen Upgrading Process (1973) Syncrude Canada Limited  
 Source [59]

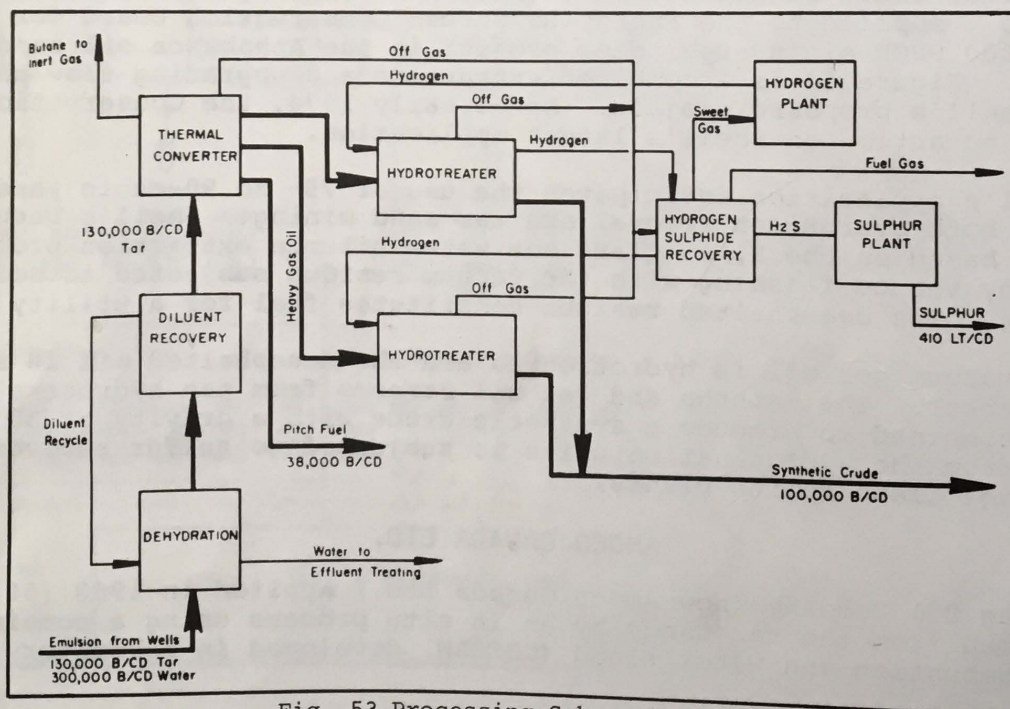
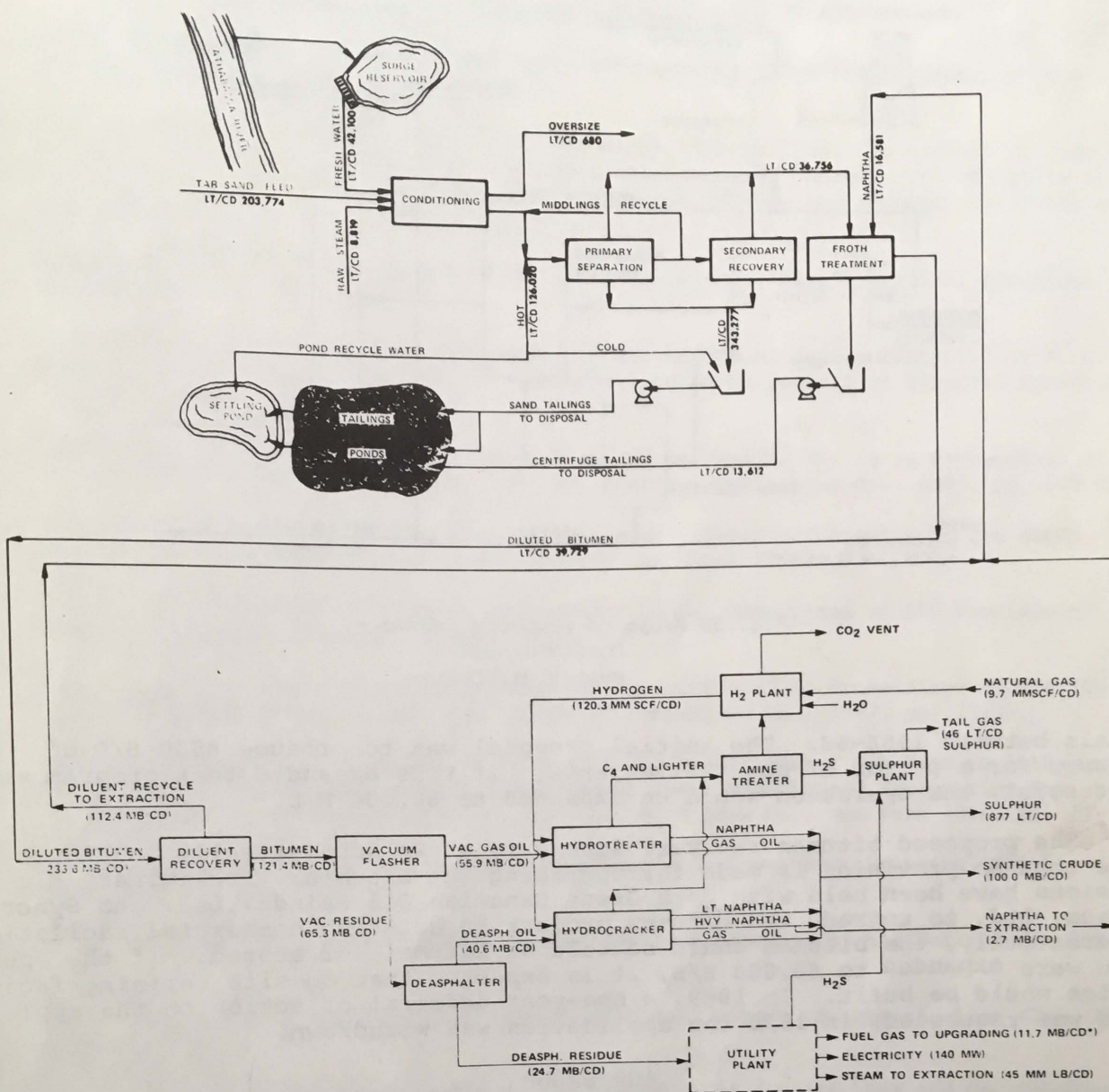


Fig. 53 Processing Scheme Proposed  
 By Shell Canada Ltd.  
 Source [21]





\*FUEL OIL EQUIVALENT

Fig. 54  
SCHEMATIC FLOW DIAGRAM  
100,000 BPCD OIL SANDS PLANT  
SHELL CANADA, LTD.  
Source [69]



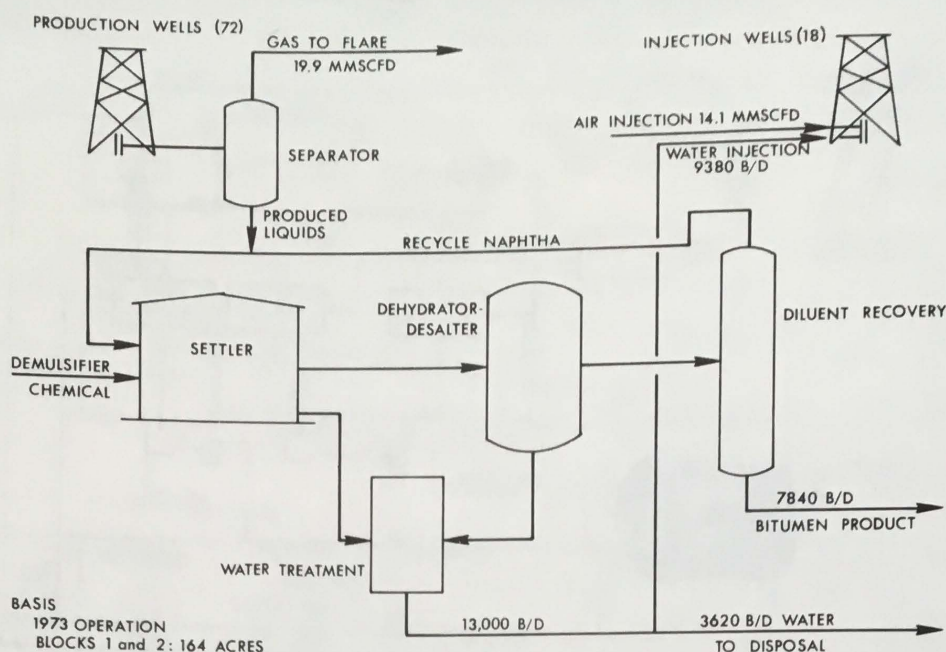


Fig. 55 Proposed Recovery Scheme -  
COFCAW Process  
Muskeg Oil Co.

trials between 1956-68. The initial proposal was to produce 8000 B/D of bitumen for a period of about five years. If this expanded test program were successful, the operation would be expanded to 60,000 B/D.

The proposed bitumen recovery scheme is shown schematically in Figure 55. Note that no provision is made for upgrading the bitumen. Preliminary discussions have been held with both Great Canadian Oil Sands, Ltd. and Syncrude Canada, Ltd. to upgrade the bitumen product in existing commercial facilities. Alternatively, the bitumen could be sold as bitumen, or stored. If the operation were expanded to 60,000 B/D, it is expected that on site refining facilities would be built. In 1969, a one-year deferral of action on the application was requested; in 1970 the application was withdrawn.

#### AOP GROUP

In early 1974, a group of five companies, headed by Petrofina Canada Ltd., applied to the Energy Resources Conservation Board for approval of a 122,500 BPCD tar sands recovery project in the Athabasca deposit area. Other members of what is called the AOP Group, in addition to Petrofina, are Pacific Petroleum Ltd., Hudson's Bay Oil and Gas Co. Ltd., Murphy Oil Co. Ltd. and CanDel Oil Ltd. The location of the proposed AOP plant is on leases held by Petrofina Canada at Daphne Island adjoining the east bank of the Athabasca river about 45 miles north of Fort McMurray.

The AOP project would employ bucket wheel excavators for overburden removal and tar sands mining, the hot water extraction process for bitumen recovery, and fluid coking for primary bitumen upgrading [70].



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